AR91

2007 Annual Report

Zargon Energy Trust

Zargon's fundamental objective has been to create value for equity holders through oil and gas exploration, development, exploitation and acquisition activities in the Western Canadian and Williston sedimentary basins. Throughout all business cycles, we seek to provide superior long term financial returns through the use of our organization's professional skills and oil and gas industry knowledge, while protecting our equity holders' existing capital by incorporating fiscally conservative policies.

Zargon remains committed to a partial cash flow distributing structure as we believe it is an effective structure for a small-intermediate sized oil and gas producer in these relatively mature Western Canadian and Williston sedimentary basins. With the commitment to deliver regular cash distributions, the structure provides the economic tension that encourages efficient capital programs, as surplus cash flow need not be reinvested in capital programs, but can be efficiently returned to equity holders.

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Zargon Highlights

	2007	2006	Percent Change
Financial			
Income and Investments ($ million)			
Petroleum and natural gas revenue	**155.51**	154.04	1
Funds flow from operations	**79.84**	82.89	(4)
Cash distributions	**36.70**	35.90	2
Net earnings	**24.55**	44.50	(45)
Net capital expenditures	**66.67**	63.37	5
Per Unit, Diluted			
Funds flow from operations ($/unit)	**4.08**	4.31	(5)
Net earnings ($/unit)	**1.45**	2.68	(46)
Cash Distributions ($/trust unit)	**2.16**	2.16	–
Balance Sheet at Year End ($ million)			
Property and equipment, net	**313.95**	283.11	11
Bank debt	**56.87**	30.04	89
Unitholders' equity	**161.48**	165.56	(2)
Total Units Outstanding at Year End (million)	**19.76**	19.42	2
Operating			
Average Daily Production			
Oil and liquids (bbl/d)	**3,675**	3,805	(3)
Natural gas (mmcf/d)	**29.31**	27.70	6
Equivalent (boe/d)	**8,560**	8,422	2
Equivalent per million trust units (boe/d)	**436**	437	–
Average Selling Price (before the impact of financial risk management contracts)			
Oil and liquids ($/bbl)	**64.71**	61.25	6
Natural gas ($/mcf)	**6.40**	6.82	(6)
Proved and Probable Reserves at Year End			
Oil and liquids (mmbbl)	**15.68**	15.93	(2)
Natural gas (bcf)	**67.36**	69.15	(3)
Equivalent (mmboe)	**26.91**	27.46	(2)
Equivalent per total unit (boe)	**1.36**	1.41	(4)
Wells Drilled, Net	**46.9**	76.2	(38)
Undeveloped Land at Year End (thousand net acres)	**362**	381	(5)

Notes:

Throughout this report, funds flow from operations, funds flow from operations per diluted unit and funds flow netbacks are now calculated inclusive of asset retirement expenditures. All prior period calculations have been restated to reflect this change.

Throughout this report, the calculation of barrels of oil equivalent ("boe") is based on the conversion ratio that six thousand cubic feet of natural gas is equivalent to one barrel of oil. For a further discussion about this term, refer to the Management's Discussion and Analysis section in this report.

Funds flow from operations is a non-GAAP term that represents net earnings and asset retirement expenditures except for non-cash items. For a further discussion about this term, refer to the Management's Discussion and Analysis section in this report.

Total units outstanding include trust units plus exchangeable shares outstanding at year end. The exchangeable shares are converted at the exchange ratio at the end of the year.

Average daily production per million trust units is calculated using the weighted average number of units outstanding during the year, plus the weighted average number of exchangeable shares outstanding for the year converted at the average exchange ratio for the year.

President's Message

Craig H. Hansen
President and Chief Executive Officer

Zargon Energy Trust reported mixed financial and operating results in 2007, its third full year of operations in a trust format. The year was highlighted by funds flow from operations of $79.84 million or $4.08 per diluted trust unit, a five percent decline from the prior year's $4.31 per diluted trust unit. During 2007, the Trust distributed $36.70 million to unitholders ($2.16 per trust unit), which was equivalent to payout ratios of 53 percent on a diluted trust unit basis or 46 percent of funds flow from operations (exchangeable shares do not receive distributions).

2007—A YEAR OF TRANSITION

2007 was a year that presented many challenges for the oil and gas industry and for trusts operating in the industry. In particular, the lingering effects of the announcement regarding the taxation of trusts in October 2006, proposed changes in the royalty regime in the Province of Alberta announced in February 2007 and reaffirmed in October 2007, volatility of commodity prices, especially reduced natural gas prices, and the dramatic strengthening of the Canadian dollar all contributed to the industry having to re-evaluate the economics of their business and their corporate structures. Although many of these events have caused a negative impact on our business, such a period of transition sets the stage for the creation of new opportunities for those organizations that plan for and are well-positioned to take advantage of changes in business cycles.

For Zargon, our fundamental objective has been to create value for equity holders through oil and natural gas exploration, development, exploitation and acquisition activities in the Western Canadian and Williston sedimentary basins. Throughout all business cycles, we seek to provide superior long term financial returns through the use of our organization's professional skills and oil and gas industry knowledge, while protecting our equity holders' existing capital by incorporating fiscally conservative policies.

For Zargon, 2007 presented challenges for us, particularly in operating and finding and development costs. Although industry activity levels have recently tempered costs, we experienced challenges in the efficiencies of our own internally generated opportunities. We have responded to these challenges by undertaking a critical evaluation of our asset base and have taken action to ensure that we high-grade our exploration, exploitation and development projects. We have also focused significant organization resources on acquisition initiatives as there is significantly less competition for both the acquisition of assets and corporations during this time of change. Fortunately, Zargon has maintained a strong balance sheet and has built up its staff and technical resources in order to ensure that we are well positioned to take advantage of opportunities that fit our long term risk adjusted return objectives.

History of Value Creation and Returns

Throughout our fifteen-year history, Zargon has successfully focused on a value creation strategy as evidenced by the following statistics:

- Fifty-seven consecutive quarters of positive net earnings.
- Over our history, Zargon has issued $69 million of equity for cash or property. Including the February 2008 cash distribution, Zargon has returned $127 million to its unitholders, while building a business entity with a market capitalization of approximately $500 million.

2008—A YEAR OF OPPORTUNITY

Looking forward to 2008, Zargon remains committed to a partial cash flow distributing structure as we believe it is an effective structure for a small-intermediate sized oil and gas producer in these relatively mature Western Canadian and Williston sedimentary basins. With the commitment to deliver regular cash distributions, the structure provides the economic tension that encourages efficient capital programs, as surplus cash flows need not be reinvested in capital programs, but can be efficiently returned to equity holders.

With the recent actions we have taken, such as the acquisition of Rival Energy Ltd. and Newpact Energy Corp. and the redirection of capital within our exploration, exploitation and development programs, we are well positioned to deliver strong returns to our equity holders. As we enter 2008, crude oil prices are at record levels but the outlook is uncertain due to a weakening US economy. For natural gas, we expect very volatile markets, however, we believe that the very low prices of the last two years are behind us. We anticipate completing additional corporate and/or property acquisitions as our industry's challenges over the past two years have restricted capital access for many of our peers, which in turn, has significantly improved corporate and property acquisition metrics. With our continued strong financial position and our now expanded feedstock of opportunities coming from recent and anticipated acquisitions, Zargon is well positioned to create significant value through oil and natural gas exploration, development, exploitation and acquisition activities in 2008.

In conclusion, 2008 could very well be another year of dramatic change, and depending on commodity prices, challenge for the oil and gas industry. At Zargon, we remain committed to executing our business strategy focused on capital program efficiencies that has proven successful over our fifteen-year history. Our goals remain, over the long term, to compound our equity value by practicing our "conventional oil and gas craft" in the Western Canadian and Williston sedimentary basins.

2007 Financial Highlights

- Revenue increased by one percent to $155.51 million.
- Funds flow from operations decreased by four percent to $79.84 million.
- Funds flow from operations per diluted trust unit decreased by five percent to $4.08.
- Net earnings decreased by 45 percent to $24.55 million.
- Net earnings per diluted trust unit decreased by 46 percent to $1.45.
- Bank debt increased by 89 percent to $56.87 million.
- Cash distributions increased by two percent to $36.70 million.
- Cash distributions per trust unit remained constant at $2.16.
- Cash distributions represented 53 percent of the year's funds flow from operations on a per diluted trust unit basis (46 percent of the Trust's funds flow from operations).

With our continued strong financial position and our now expanded feedstock of opportunities coming from recent and anticipated acquisitions, Zargon is well positioned to create significant value through oil and gas exploration, development, exploitation and acquisition activities in 2008.

Management Team

(LEFT TO RIGHT)

JASON B. DRANCHUK
Controller and Treasurer

MARK I. LAKE
Vice President, Exploration,
Team Lead,
West Central Alberta
Core Area

HENRY J. BAIRD
Vice President, Exploitation,
Team Lead,
Williston Basin Core Area

CRAIG H. HANSEN
President and
Chief Executive Officer

BRIAN G. KERGAN
Vice President, Corporate
Development and Reserves,
Team Lead,
Alberta Plains Core Area

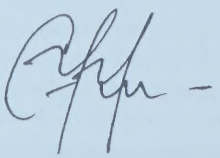
DANIEL A. ROULSTON
Executive Vice President,
Operations

LORNE D. SCHWETZ
Vice President, Land

BRENT C. HEAGY
Executive Vice President
and Chief Financial Officer

ACKNOWLEDGEMENTS

We are thankful for the commitment, skill and support of our staff as we continue to strive to efficiently execute our oil and natural gas business in order to enhance the long term value of Zargon. We also extend our gratitude to our Board of Directors for their valuable wisdom, advice and support. In particular, we thank John McCutcheon, who announced his retirement in 2007 as Chairman of the Board, for his many years of service since the founding of Zargon and we look forward to his continued participation as a member of the Board. Also, James J. Lawson has decided not to stand for re-election at the upcoming annual meeting and we thank him for his valuable counsel over his past two years on the Board. Finally, on behalf of all employees and our Board, I would like to express our appreciation to our equity holders for their confidence and support for our unwavering commitment to value creation through the focused execution of our conventional oil and natural gas business.



C.H. Hansen

President and Chief Executive Officer

March 12, 2008

Questions and Answers about Zargon's Long Term Vision

Q What is Zargon's long term vision regarding its business and its structure?

- Zargon is first and foremost an oil and gas company practicing the "conventional oil and gas craft" in the Western Canadian and Williston sedimentary basins.
- Zargon has, and continues to embrace, a partial cash flow distributing model that implicitly encourages capital program efficiencies in these mature basins that are characterized by strong cash flows but only moderate returns from capital projects. By working in a trust structure, these distributions are transferred to our equity holders in a tax preferred manner. Post 2010, Zargon will seek to find a structure that will continue to allow us to effectively work our oil and natural gas business in a partial cash flow distributing model.

Q What are Zargon's long term commodity price expectations?

- Both oil and natural gas prices are very volatile and Zargon must ensure that it remains viable in circumstances where prices are much lower.
- We cannot predict short term price trends and will continue to implement an eighteen-month hedging program for 20-35 percent of our working interest volumes. These hedges will help ensure that we can fund our upcoming capital programs and maintain our current distribution per trust unit.
- In the long run, we believe that there continues to be a secular uptrend for oil and natural gas commodity prices due to world supply and demand trends. We also believe that due to the developing liquefied natural gas markets, natural gas will eventually be priced on a world market basis that will more closely track the energy equivalency levels than have recently been experienced.
- These pricing views encourage us to build long term oil and natural gas assets.

Q What are Zargon's core competencies?

- Oil Exploitation: Over the years, we have demonstrated a core competency in improving recovery factors and production volumes from existing oil reservoirs through waterfloods, horizontal wells and production optimizations.
- Natural Gas Exploration: We have also demonstrated a core competency in discovering new natural gas reserves in the Alberta Plains core area and, more recently, in the Peace River Arch property. Our exploration techniques rely heavily on detailed geology and seismic interpretations.
- Value Enhancing Acquisitions: In our earlier years, and now with our recently announced transactions, we have demonstrated an ability to acquire assets at reasonable prices and create additional value through exploration and exploitation activities on these acquired assets.

2007 Operating Highlights

Net capital expenditures in 2007 increased five percent to $66.67 million, with $63.54 million allocated to exploration and development activities.

- Drilled a 46.9 net well program, with a 94 percent success rate, that delivered 32.7 net natural gas wells and 11.6 net oil wells.
- Total production increased two percent to 8,560 barrels of oil equivalent per day.
- Zargon's 2007 capital investment program replaced production by 90 percent (proved reserves) and 83 percent (proved and probable reserves).
- Proved and probable reserves decreased two percent to 26.91 million barrels of oil equivalent. Proved and probable finding, development and acquisition ("FD&A") costs were $26.53 per barrel of oil equivalent (inclusive of the change in future development costs).

2007 Key Sustainability Metrics

Zargon defines its sustainability targets in terms of the following six parameters.

PRODUCTION

Zargon's production averaged 436 barrels of oil equivalent per day per million trust units, essentially unchanged from last year's rate of 437 barrels of oil equivalent per day per million trust units.

RESERVES

Zargon's year end proved and probable reserves were 1.36 barrels of oil equivalent per total unit, a four percent decrease from last year's reserves of 1.41 barrels of oil equivalent per total unit.

DISTRIBUTIONS

Cash distributions were $2.16 per trust unit, unchanged from the prior year's distribution per unit.

Q In addition to our core competencies, is there anything else that we are working on?

- We seek to build core competencies with natural gas development and natural gas resource projects. For both of these initiatives, we will continue to invest time and capital to further develop these competencies.
- Natural Gas Development: Over the years, we have had success in developing known natural gas accumulations in the Jarrow and Hamilton Lake properties. In 2007, these programs did not meet economic targets and we are deferring further development programs until a combination of improved natural gas prices, modified completion techniques and/or reduced costs are available to provide improved economic returns.
- Natural Gas Resource Projects: As our long term view of natural gas pricing remains very positive, we wish to build natural gas resource opportunities that can be harvested in the future as prices and technology enables strong future economic returns. Our related efforts to build a large natural gas resource inventory with the Pembina shallow natural gas project has not met economic standard and we are currently suspending further capital expenditures until improved returns can be forecasted.

Questions and Answers about Recent Developments

Q What about the recent legislative developments?

- On October 31, 2006, the Canadian Federal Government announced regulations that significantly reduce the tax advantages of trust structures. On June 12, 2007, the Federal Government enacted new legislation to implement these changes. These changes are scheduled to be implemented January 1, 2011.
- On October 25, 2007, the Alberta Government released a report entitled "The New Royalty Framework" ("NRF"), which outlines planned changes to the Government of Alberta's royalty program. These changes are scheduled to be implemented January 1, 2009.
- Both the trust legislation and the proposed royalty legislation are very damaging to the smaller public and private oil and natural gas entities that practice the "conventional oil and gas craft" in the Western Canadian sedimentary basin.
- Ultimately, we believe that these developments will result in a significant reduction in the number of competitors working the conventional oil and gas business. This reduced competition will enable improved access and returns for the entities that continue to practice the "conventional oil and gas craft" in the Western Canadian sedimentary basin.

Q How have these developments impacted the industry?

- These legislative developments combined with two years of poor natural gas pricing has led to weaker equity markets for small and junior Canadian oil and natural gas producers which in turn has resulted in restricted equity

financing options and higher debt levels for a component of our business. With these developments we have observed the following:

- Improved values are available for certain oil and natural gas property and corporate acquisitions.
- Crown land sales, farm-ins and joint venture opportunities are more readily available.
- In most areas, improved access to field services at reasonable costs are now available.

Q How is Zargon responding to these developments?

■ Zargon is well positioned to take advantage of these opportunities that have become available. We will use our strong balance sheet and relatively strong equity price (compared to junior and private oil and gas companies) to acquire assets in accretive corporate or property transactions.

■ Specifically, we will seek to acquire Alberta natural gas properties from undercapitalized privates, juniors and trusts. The natural gas properties should bring:

- Development, exploration or resource potential.
- Improved (ultimately) corporate decline rates.
- If possible, additional tax pools.

■ We will also seek to acquire exploitable oil properties in all of our core areas. The oil properties should bring:

- Waterflood and horizontal drilling exploitation or production optimization opportunities focused on increasing reservoir recovery factors.
- Significant long term potential, although transactions may not initially appear accretive on a cash flow or production basis.

Q Zargon's finding costs in 2007 were substandard; what is our response?

■ Zargon's 2007 finding, development and acquisition costs (including future capital) of $22.21 per barrel of oil equivalent for proved reserves and $26.53 per barrel of oil equivalent for proved and probable reserves did not meet our expectations.

■ We have responded by:

- Reducing exploration and development capital budgets to $50 million from $60 million, thereby increasing economic tension in the capital allocation process.
- Implementing more rigorous economic hurdle rates for capital projects.
- Altering capital specific programs:
  - Williston Basin exploration programs have been suspended.
  - Capital programs at the West Central Alberta Highvale and Pembina properties are limited to maintenance and sustaining programs.
  - Natural gas development programs in the Alberta Plains are deferred until better returns are available.

2007 Key Sustainability Metrics (cont'd)

BALANCE SHEET QUALITY

Zargon's 2007 year end debt net of working capital (excluding unrealized risk management assets and liabilities) of $62.30 million represented a debt to funds flow ratio of approximately 0.8 years, up from the prior year's comparative of 0.5 years.

ASSET QUALITY

Zargon's asset quality in terms of average crude gravity (30 degrees API), and natural gas/oil mix (57 percent natural gas production) did not change materially in 2007. The year end proved producing, proved total and proved and probable reserve life indices decreased an average of seven percent to 5.4, 5.8 and 8.4 years, respectively.

TAX HORIZON

Zargon's tax pools increased in 2007 to a year end balance of approximately $148 million, compared to the 2006 year end balance of $113 million.

Questions and Answers about Zargon's Business Strategies

Q As we move to the post 2010 trust tax legislation implementation, will Zargon need to modify its distribution policy?

■ Post 2010, Zargon will seek a structure that permits us to continue to practice our oil and natural gas exploration, exploitation, development and acquisition business executed within a partial cash flow distributing model. We anticipate that distribution percentages (but not necessarily distributions per unit) will decline from historical levels in order to access the tax sheltering benefits of field capital expenditures.

■ As we move to a lower distribution percentage (say 35 percent) we will seek to augment our distributions with a modest level of growth on a trust unit basis. To Zargon, this growth is defined as increasing reserves and production on a per unit basis. These growth targets must be debt adjusted and cannot come with the deterioration of the quality or character of our assets.

■ The rate of growth necessary to meet targets will depend on our distribution percentages. At a minimum, we would seek to deliver a total return in excess of 10 percent per year. This return would be defined as the summation of the annual growth percentage and the distribution percentage calculated as a yield on our current net asset value. We believe that this business model, over the long term, can deliver sufficient compounded returns to warrant premium equity valuations that, in turn, provide a cost of capital advantage for further expansions.

Q Does Zargon need to merge or bulk-up to improve its cost of capital?

■ Not from our perspective: We believe that our investors are willing to support competent oil and natural gas practitioners who deliver value-added exploration, exploitation, development and acquisition capital programs.

■ In this relatively mature sedimentary basin, we find that our conventional oil and natural gas projects tend to provide production additions in 500 barrels of oil equivalent per day increments. At our current size, and with our inherent production declines, we only need five or six good ideas a year to meet our sustainability and growth objectives. By limiting our growth in absolute terms we are able to allow our senior technical managers to continue to focus on their "conventional oil and gas craft."

■ We do, however, agree that there is a minimum trust size required to justify the growing public company/regulatory costs and we are targeting to reach the 12,000 barrels of oil equivalent per day level within the next two years, with further growth anticipated to follow.

Q Considering our recent results, have we revisited our sustainability assumptions?

■ The percentage of the cash flows required to sustain production and replace reserves will vary from year to year, and will depend on the amount of cash flows, the inherent property decline rate that we are replacing, the availability and cost of services, our tax horizons, and the quality of our projects.

■ On the basis of our three-year history of operating in the sustainable trust format, we have concluded that with our current production declines, we will need to reinvest 50 to 65 percent of our cash flow to sustain our properties. This ratio implies a corporate recycle ratio target of 1.5 to 2.0 times, which of course will depend on where we are within the ebb and flow of the oil and natural gas business cycle. We recognize that these are challenging targets, but they are more readily obtained in this new environment of reduced competition for services, Crown land and acquisitions.

Q What is the impact of these sustainability assumptions on our short term distributions?

■ Zargon will be slow to implement upward or downward adjustments to the current monthly distribution level of $0.18 per unit. If commodity prices, volumes per trust unit and/or cash flow generation improve, we will allow the distribution percentage to drop towards the target 35 percent level that we anticipate that we will be working with in the post 2010 period.

■ We will continue to maintain a strong balance sheet and a significant forward hedging program in order to support the continuation of both our capital programs and our distributions in short term periods of reduced cash flows resulting from depressed commodity prices.

■ Ultimately, our most important consideration is the protection of our equity holders' existing capital by incorporating fiscally conservative policies. Consequently, we will reduce distributions when balance sheet considerations necessitate distribution cuts or if we can clearly demonstrate that the transfer of funds from distributions to our capital programs will provide substantially improved returns.

Q How will we obtain our stated objective of long term modest growth per unit?

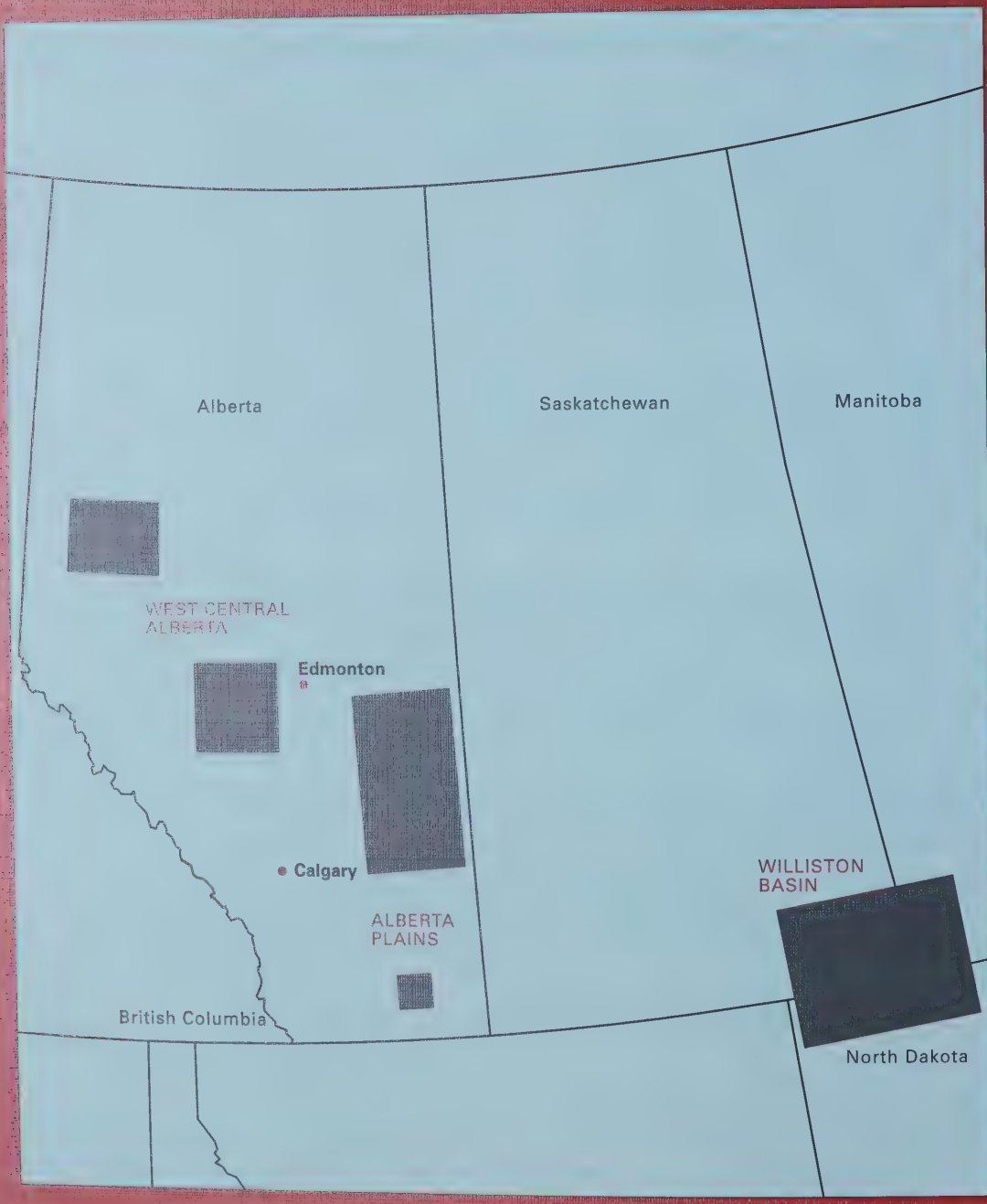
■ Once sustainability targets are met, we can focus on growth provided from capital generated from unutilized bank lines, equity and cash flows attributed to exchangeable shares. This capital will be used in an accretive manner through:

- The acquisition of properties that provide current production and reserves plus replenish the undeveloped land and oil-in-place feed stocks.
- And on occasion, expanded organic development programs to capture specific opportunities.

Q What are the biggest challenges and opportunities for Zargon in 2008?

■ Zargon's biggest challenges and opportunities relate to the same issues. In recent quarters, Zargon's capital programs have been plagued by increased costs and substandard efficiencies. We have responded to these challenges by undertaking a critical evaluation of our asset base and have taken both staffing and capital allocation adjustments to ensure that we high-grade our exploration, exploitation and development projects. The timing of these adjustments has coincided with our industry's evolution to an environment of improved opportunities. We are very optimistic about what we can accomplish in 2008.

Zargon's activities are focused in three distinct core areas. The Alberta Plains and West Central Alberta core areas provide the base for Zargon's natural gas exploration and development businesses. The Williston Basin core area, and now the Alberta Plains core area with the Rival acquisition, both provide the foundation for Zargon's oil exploitation business. Each of these businesses, while having common elements, also have distinct characteristics.



Core Areas and Business Strategies

Daniel A. Roulston
Executive Vice President,
Operations

Natural Gas Exploration and Development Business

Zargon's natural gas exploration and development activities are concentrated in two core areas:

- The Alberta Plains core area consists of generally mature natural gas producing properties and provides the majority of the Trust's natural gas production and reserves. This existing production is predominantly operated with high working interest and produced into Zargon owned production infrastructure. This core area provides both seismically defined Mannville exploration prospects that are characterized by strong productivities but moderate reserves, and shallow natural gas (Viking and Mannville) down-spacing and commingling development projects that provide lower initial rates but longer reserve life indices.
- The West Central Alberta core area properties are more exploratory in nature and are located in three specific regions where Zargon has accumulated a considerable undeveloped land position. Capital costs for the West Central Alberta exploration wells tend to be much larger than the Alberta Plains wells, and in some circumstances the natural gas reserves and production rates can be significant.

In general, Zargon's natural gas exploration activities are based on geophysical and geological analysis to identify and pursue drilling opportunities on the Trust's substantial inventory of undeveloped lands. The natural gas development activities are based on lower productivity and more regional projects at the Jarrow, Hamilton Lake and Pembina properties and are developed when acceptable returns are available. These returns are dependent on both the commodity prices and the capital costs of the development programs. Zargon's undeveloped lands are situated in large concentrated blocks and, for the most part, are accessible for all-season operations.

Oil Exploitation Business

Zargon's oil business is built on the exploitation of long-life oil properties that are characterized by large under-exploited volumes of oil-in-place. Zargon's oil properties are primarily located in the Williston Basin core area of southeastern Saskatchewan, southwestern Manitoba and immediately across the border in the northern counties of North Dakota. Recently, Zargon's oil exploitation activities have expanded into the Alberta Plains core area with last year's Taber exploitation drilling successes and with the January 2008 acquisition of the Rival Bellshill Lake property. The Trust utilizes reservoir engineering, three-dimensional ("3D") seismic, horizontal drilling and detailed geological mapping to identify opportunities to increase daily production volumes and to maximize the ultimate oil recoveries from this large oil-in-place resource base. The oil exploitation initiatives frequently include the implementation or modification of waterflood projects.

Rival Energy Ltd. Corporate Acquisition

On January 23, 2008, Zargon concluded the corporate acquisition of Rival Energy Ltd. for a total consideration of approximately $47.10 million. These acquired assets produced 956 barrels of oil equivalent per day in the 2007 fourth quarter (2.17 million cubic feet per day of natural gas and 595 barrels per day of oil and liquids), with the majority of the production coming from the Bellshill Lake property in the Alberta Plains. In a report dated February 28, 2008, the independent engineering consultant, GLJ Petroleum Consultants, assigned the Rival assets 2007 year end proved and probable reserves of 2.42 million barrels of oil equivalent, which was comprised of 1.48 million barrels of oil and liquids plus 5.48 billion cubic feet of natural gas.

2007 CORE AREA STATISTICAL SUMMARY

	Alberta Plains	West Central Alberta	Williston Basin	Total
Production (boe/d)	3,911	1,656	2,993	8,560
Production growth/(decline) (percent)	5	8	(5)	2
Proved and probable reserves (mboe)[1]	9,766	3,879	13,262	26,907
Annual reserve growth/(decline) (percent)	(1)	2	(4)	(2)
Undeveloped land (thousand net acres)	128.3	164.6	68.7	361.6
Undeveloped land growth/(decline) (percent)	6	(19)	17	(5)
Core area cash flow ($ million)[2]	34.87	13.70	41.57	90.14
Capital program ($ million)	30.33	18.01	17.06	65.40
Drilling program (net wells)	32.1	6.2	8.6	46.9
Three-year FD&A costs ($/boe)[3]	18.77	35.64	15.11	19.58

1. *Proved and probable reserves are trust working interest reserves before royalties (6:1).*
2. *The summation of the 2007 core area cash flows are $90.14 million, which compares to the Trust's 2007 funds flow from operations of $79.84 million. The term "core area cash flow" is defined as petroleum and natural gas revenue for a core area, net of royalties and production expenses. The term "funds flow from operations" is defined in the MD&A section of this report. The difference between the summation of the core area cash flows and the funds flow from operations is comprised of the corporate charges including general and administrative expenses, interest and financing costs, realized risk management gains/losses, corporate taxes and asset retirement expenditures.*
3. *The reported proved and probable finding, development and acquisition ("FD&A") costs include an allowance for the change in future capital expenditures. This calculation also includes allowances for prior year reserve revisions.*

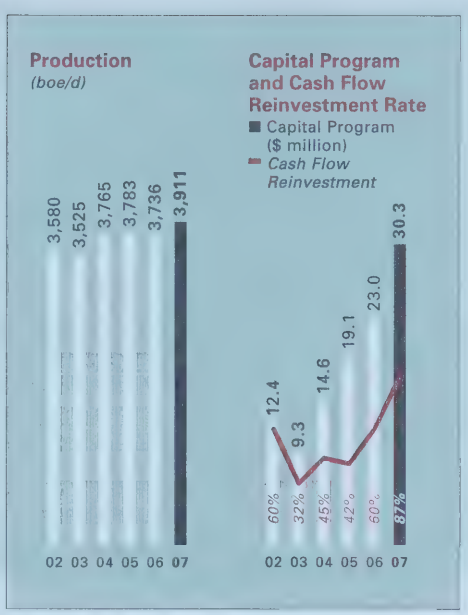
Alberta Plains

Brian G. Kergan
Vice President,
Corporate Development
and Reserves.
Team Lead, Alberta Plains
Core Area

The Trust's Alberta Plains core area is located in the eastcentral and southeastern regions of Alberta and is characterized by relatively shallow wells and all-season surface access.

2008 Alberta Plains Key Initiatives

- Efficiently integrate the 779 barrels of oil equivalent per day of production and the 1.81 million barrels of oil equivalent of proved and probable reserves acquired in the Rival corporate transaction into the property portfolio.
- Continue with the seismically focused exploration programs in the greater Jarrow area.
- Initiate development, exploration and field optimization activities at the newly acquired Bellshill property.
- Continued development of the Taber oil property through horizontal drilling and waterflood modifications.
- Defer Hamilton Lake and Jarrow natural gas Viking and Mannville development programs until improved economic returns can be demonstrated.
- Efficiently execute a $24 million capital program that delivers an Alberta Plains average 2008 production rate of approximately 4,700 barrels of oil equivalent per day. This capital program includes the drilling of approximately 29 net wells at the Jarrow, Bellshill and Taber properties.



The Alberta Plains core area provides substantial cash flows that support trust distributions and also funds the trust's reinvestment programs required to maintain stable production volumes and reserves. The area brings a large undeveloped land inventory and, together with the Rival transaction, a substantial inventory of oil exploitation opportunities, which provide the feedstock for future gas exploration, gas development and oil exploitation programs.

The Trust's Alberta Plains core area is located in the eastcentral and southeastern regions of Alberta and is characterized by relatively shallow wells and all-season surface access. This core area delivered 69 percent of Zargon's total natural gas production in 2007.

The Alberta Plains production volumes have been maintained at a relatively stable level since 2001 through exploration and development drilling programs on the Trust's land base. Typically, these capital programs have been funded from about 50 percent of the core area's property cash flow. In 2007, the Alberta Plains core area generated $34.87 million of property cash flow, of which $30.33 million or 87 percent of the property cash flow was reinvested in the core area. With these expenditures, Zargon increased the core area's production volumes by five percent and essentially maintained the core area's proved and probable reserves. During 2007, the Alberta Plains capital programs provided proved and probable reserve additions at a cost of $23.80 per barrel of oil equivalent. With the early 2008 acquisition of Rival Energy Ltd., a significant oil exploitation and development opportunity at Bellshill Lake has been added to the core area.

Alberta Plains

	2007	2006	2005	2004	2003
Average Production					
Oil and liquids (bbl/d)	**563**	520	553	595	640
Natural gas (mmcf/d)	**20.09**	19.29	19.38	19.02	17.31
Equivalents (boe/d)	**3,911**	3,736	3,783	3,765	3,525
Total Proved & Probable Reserves[1]					
Oil and liquids (mbbl)	**2,321**	2,079	1,962	1,932	1,840
Natural gas (bcf)	**44.67**	46.44	46.00	46.57	44.01
Equivalents (mboe)	**9,766**	9,818	9,625	9,694	9,208
Undeveloped Lands					
Net acres (thousands)	**128.3**	120.5	120.5	146.0	185.4
Drilling Activities					
Net wells	**32.1**	39.5	25.1	21.4	12.8
Core Area Cash Flow ($ million)	**34.87**	38.23	45.68	32.71	29.33
Capital Expenditures ($ million)					
Net property and corporate acquisitions/ (dispositions)	**0.48**	0.79	0.03	0.60	(1.16)
Undeveloped land, seismic and geological	**5.58**	3.12	2.41	3.09	3.04
Drilling and completions	**14.44**	12.88	11.08	7.66	4.81
Equipping and facilities	**9.83**	6.16	5.55	3.22	2.58
Total expenditures	**30.33**	22.95	19.07	14.57	9.27
Capital Program Efficiencies					
Finding, development and acquisition costs ($/boe)[2]	**23.80**	18.03	14.36	7.56	65.03

1. *Proved and probable reserves are trust working interest reserves before royalties (6:1).*
2. *The reported proved and probable finding, development and acquisition ("FD&A") costs include an allowance for the change in future capital expenditures. This calculation also includes allowances for prior year reserve revisions and the 2003 reserve definition changes relating to National Instrument 51-101 Standards of Disclosure.*

Going forward, Zargon has an expanded inventory of Alberta Plains opportunities that should provide stable 2008 Alberta Plains production volumes at the new post Rival acquisition levels. These opportunities include natural gas exploration, oil exploitation and, ultimately, natural gas development in the following key properties:

JARROW

The Jarrow property continues to be the Trust's most significant producing natural gas property where Zargon produced 16.08 million cubic feet of natural gas per day and 12 barrels of oil and liquids per day in 2007 primarily from the Mannville and Viking formations. This property is characterized by high working interests, ownership and operatorship of significant pipeline and gas processing facilities and a large inventory of prospects on a 108 thousand net acre undeveloped land inventory. At December 31, 2007, Jarrow undeveloped land inventory represented a 19 percent increase over the prior year. This increase is attributable to the freehold leasing program during the year as well as Crown acquisitions during a year of reduced industry competition for land. Reflecting the reduced competition for Crown land in the current business environment, Zargon will look to expand its Jarrow undeveloped land inventory in 2008.

During 2007, Zargon drilled 16.1 net (19 gross) wells at Jarrow, resulting in 15.5 net natural gas wells and 0.6 net dry holes. The Trust also shot 94 kilometres of two-dimensional ("2D") seismic as part of its ongoing exploration and development programs.

In 2007, the Trust focused on multi-well development programs in the Viking and Mannville reservoirs in addition to grassroots seismically based Mannville exploration. In 2008, the emphasis will be focused on Mannville exploration, with the drilling of 19 net wells that are mostly located in the western and southern portions of the property.

HAMILTON LAKE

The Hamilton Lake property produced 3.31 million cubic feet of natural gas per day and 88 barrels of oil and liquids per day in 2007 from the Mannville and Viking formations. The property's key asset is a 31 thousand net acre developed and undeveloped unit that has significant development potential in the lower permeability but extensive first Viking sand formation. The property also provides an additional 13 thousand net undeveloped acres of deeper Mannville rights.

In 2007, Zargon drilled 13.0 net (13 gross) wells at Hamilton Lake resulting in 13.0 net first Viking shallow natural gas wells. Although commercial, the returns on this Viking development program did not meet internal expectations. Consequently, at this time Zargon is not planning any 2008 Viking development drilling at Hamilton Lake until a combination of improved natural gas prices, modified completion techniques and/or reduced costs are deemed to provide improved economic returns.

BELLSHILL LAKE

The Bellshill Lake oil property is located immediately south of Jarrow and was acquired as part of the acquisition of Rival Energy Ltd., which closed on January 23, 2008. This property will provide significant oil development drilling, exploitation drilling and production optimization opportunities from existing wells. In the fourth quarter of 2007, the Bellshill property produced approximately 549 barrels of oil and liquids per day and 0.18 million cubic feet of natural gas per day to the Zargon acquired interest. For 2008, Zargon is planning on an eight net well drilling program along with multiple optimization and workover activities on existing wells.

TABER

Taber is a medium gravity oil property within the Alberta Plains core area and is an emerging focus area for Zargon. In 2007, this property produced 463 barrels of oil and liquids per day and 0.69 million cubic feet of natural gas per day. There were 3.0 net horizontal oil wells drilled in 2007. Building on encouraging results from 2007, Zargon is planning two additional net horizontal wells in 2008 to further develop the potential of this area.

West Central Alberta

Mark I. Lake
Vice President, Exploration.
Team Lead,
West Central Alberta Core Area

The West Central Alberta core area currently delivers approximately 31 percent of Zargon's natural gas production and, with exploration success, can provide the opportunity to grow its natural gas production volumes.

Zargon's West Central Alberta core area is located northwest of Edmonton in central Alberta and is comprised of three natural gas producing regions that provide the Trust with a varied inventory of natural gas exploration and development opportunities. This core area currently delivers approximately 31 percent of Zargon's natural gas production and, with exploration success, can provide Zargon the opportunity to grow its natural gas production volumes. In 2007, Zargon spent $18.01 million of capital in the West Central Alberta core area, which represented 131 percent of the $13.70 million of property cash flow generated by this area. With these expenditures, Zargon drilled 6.2 net wells in this core area that resulted in 4.2 net natural gas wells and 2.0 net dry holes.

During 2007, the West Central Alberta core area's production increased eight percent to 1,656 barrels of oil equivalent per day. With a refocused field program in 2007, Zargon was able to improve results in this core area compared to prior years. Tie-ins from the previous year's drilling program and some 2007 drilling successes were able to offset the expected natural declines of gas production.

Although the West Central Alberta core area's undeveloped acreage decreased by 19 percent to 165 thousand net acres in the year, the core area's proved and probable reserves showed a two percent increase to 3.88 million barrels of oil equivalent. The corresponding finding and development costs of $23.50 per barrel of oil equivalent showed a significant reduction from the prior trends, but still did not meet internal expectations.

West Central Alberta

	2007	2006	2005	2004	2003
Average Production					
Oil and liquids (bbl/d)	**166**	168	209	218	260
Natural gas (mmcf/d)	**8.94**	8.19	8.25	9.56	7.27
Equivalents (boe/d)	**1,656**	1,534	1,584	1,814	1,472
Total Proved & Probable Reserves[1]					
Oil and liquids (mbbl)	**530**	406	455	499	585
Natural gas (bcf)	**20.09**	20.27	21.49	22.00	22.19
Equivalents (mboe)	**3,879**	3,785	4,036	4,166	4,283
Undeveloped Lands					
Net acres (thousands)	**164.6**	202.2	197.7	184.9	173.6
Drilling Activities					
Net wells	**6.2**	14.7	14.1	20.6	17.8
Core Area Cash Flow ($ million)	**13.70**	13.41	18.57	16.16	12.25
Capital Expenditures ($ million)					
Net property and corporate acquisitions/ (dispositions)	**0.90**	(0.80)	0.13	0.40	(2.33)
Undeveloped land, seismic and geological	**4.44**	2.68	3.20	4.77	7.50
Drilling and completions	**7.85**	11.64	9.74	14.62	7.63
Equipping and facilities	**4.82**	4.77	2.70	2.33	2.75
Total expenditures	**18.01**	18.29	15.77	22.12	15.55
Capital Program Efficiencies					
Finding, development and acquisition costs ($/boe)[2]	**23.50**	59.19	38.23	40.95	13.63

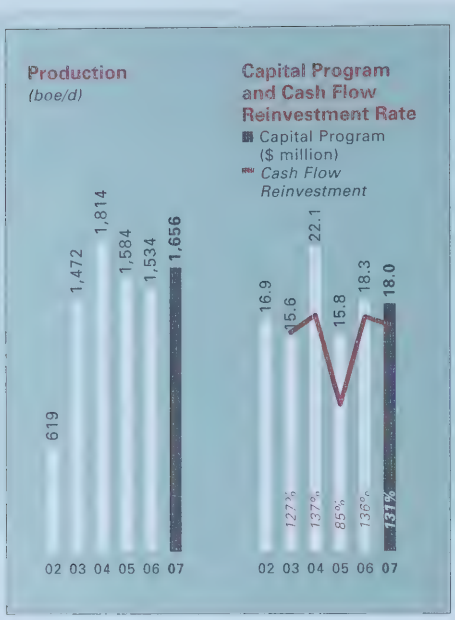
1. *Proved and probable reserves are trust working interest reserves before royalties (6:1).*
2. *The reported proved and probable finding, development and acquisition ("FD&A") costs include an allowance for the change in future capital expenditures. This calculation also includes allowances for prior year reserve revisions and the 2003 reserve definition changes relating to National Instrument 51-101 Standards of Disclosure.*

During the first nine months of 2008, Zargon will tie-in 3.2 net natural gas wells into third party facilities, which should offset declines and maintain production at the new post Rival acquisition levels. Zargon will also proceed with a Peace River Arch exploration program that could deliver significant reserves and production in the future. A summary of Zargon's key properties in the West Central Alberta core area is summarized below:

GREATER HIGHVALE

Zargon's 28 thousand net acres of undeveloped land in the Greater Highvale property is centered around the Paul First Nation land block located west of Edmonton. Zargon owns and operates natural gas production infrastructure in the area and has historically pursued seismically defined structural and stratigraphic prospects at medium depths. In 2007, Zargon drilled 1.5 net natural gas wells and shot a 31 kilometre 2D seismic program in this area. Production for Greater Highvale averaged 2.95 million cubic feet per day of natural gas and six barrels per day of oil and liquids production in 2007.

Although Zargon's total returns in the last few years for the Greater Highvale area have met expectations, the production tends to be unreliable as the wells are characterized by prolific rates that are unpredictably truncated by water influx. The variability of these production profiles is very challenging to manage within Zargon's partial distribution trust model and, consequently, Zargon has elected to limit further capital expenditures in this area to maintenance and lease sustaining activities. In 2008, one net natural gas exploration well is planned for the Highvale area.



2008 West Central Alberta Key Initiatives

- Efficiently integrate the 177 barrels of oil equivalent per day of production and 608 thousand barrels of oil equivalent of proved and probable reserves provided from the Rival acquisition into the property portfolio.
- Continue with selected Peace River Arch exploration programs, building on late 2006 and early 2008 exploration successes in the Progress, Saddle Hills and Kakut areas.
- Maintain the Highvale and Pembina asset bases with maintenance and sustaining capital.
- Efficiently execute a $13 million capital program that delivers a West Central Alberta average 2008 production rate of approximately 1,900 barrels of oil equivalent per day. This capital program includes the drilling of approximately six net wells, primarily located at the Peace River Arch property.

PEMBINA SHALLOW GAS

Over the last seven years, Zargon has been pursuing the exploration and development of shallow under-pressured Scollard and Horseshoe Canyon natural gas sands in the Pembina area at depths up to 900 metres. Zargon has an inventory of 54 thousand net acres of undeveloped land on this prospect. In 2007, Zargon drilled 3.0 net natural gas wells in the Pembina area and the property provided 2.51 million cubic feet per day of natural gas and 130 barrels per day of oil and liquids production to Zargon's interest.

A review of the long term results for the Pembina programs clearly demonstrates that this property has not provided a proper economic return for Zargon. This is a disappointing observation as numerous gas bearing trends have been identified, but the related reserves and production rates have not been able to support the high costs for surface lease construction, fracture stimulations, pipelining and third party processing. Consequently, Zargon is deferring further drilling at Pembina until a combination of improved natural gas prices, modified completion techniques and/or reduced costs are deemed to provide improved economic returns. In the meantime, Zargon will continue with maintenance activities and selected tie-ins of 1.6 net wells that meet economic targets.

PEACE RIVER ARCH EXPLORATION

In the Peace River Arch exploration area, Zargon is pursuing multi-zone gas exploration prospects at drilling depths ranging up to 2,100 metres. The Peace River Arch exploration strategy is more "grassroots" than in other areas as the Trust develops prospects, posts land, shoots seismic and drills high graded prospects. Zargon has an 83 thousand net acre undeveloped land inventory that is generally characterized by year round surface access and mostly sweet natural gas multi-zone prospects.

In 2007, the Trust drilled 1.7 net wells in the Peace River Arch area that resulted in a 0.7 net natural gas well and 1.0 net abandonment. Production for the area averaged 3.48 million cubic feet per day of natural gas and 30 barrels per day of oil and liquids. During 2008, Zargon is planning an active exploratory drilling program with 4.7 net wells scheduled in the first half of year at Progress South, Saddle Hills, Rycroft, Kakut, and Hamelin Creek. Success with this exploration program could lead to follow-up locations and an expanded budget in the second half of 2008. The target horizons include Bluesky, Gething, Charlie Lake, Montney, Doig and Debolt and have been identified by seismic and geological mapping. In the first half of the year, Zargon will also proceed with the tie-in of 1.7 net natural gas wells that were drilled in prior years.

Williston Basin

Henry J. Baird
Vice President, Exploitation, Team Lead Williston Basin Core Area

In 2007, the Williston Basin contributed about 80 percent of the Trust's oil and liquids production and 82 percent of the Trust's proved and probable oil and liquids reserves.

The Williston Basin core area is characterized by a very stable oil production base that offers significant long term exploitation opportunities. The core area provides substantial cash flows that can be allocated to trust cash distributions or reinvested to provide production growth.

The Williston Basin properties are located within relatively close proximity in southeast Saskatchewan, southwest Manitoba and in the northern counties of the State of North Dakota. The properties produce light and medium gravity oil from carbonate reservoirs at depths up to 1,500 metres. In 2007, the Williston Basin contributed about 80 percent of the Trust's oil and liquids production, 82 percent of the Trust's proved and probable oil and liquids reserves and provides a long proved and probable reserve life of 12.5 years.

Zargon's Williston Basin producing reservoirs are characterized by moderate permeability and a large remaining oil-in-place. By the nature of the physical characteristics of these reservoirs, the wells demonstrate relatively stable production with shallow annual production declines and, accordingly, long reserve life indices.

Through exploitation projects, Zargon attempts to find methods to increase oil recoveries from these reservoirs. Generally, Zargon uses a combination of exploitation techniques including pressure maintenance by water injection, 3D seismic and horizontal drilling to unlock additional oil reserves. Frequently, optimizing pressure support in the oil reservoir by water injection is the first step in the exploitation process. With pressure support established, Zargon seeks to characterize the reservoirs through 3D seismic analysis and interpretation, which is followed by horizontal wells designed to increase recoveries and accelerate production.

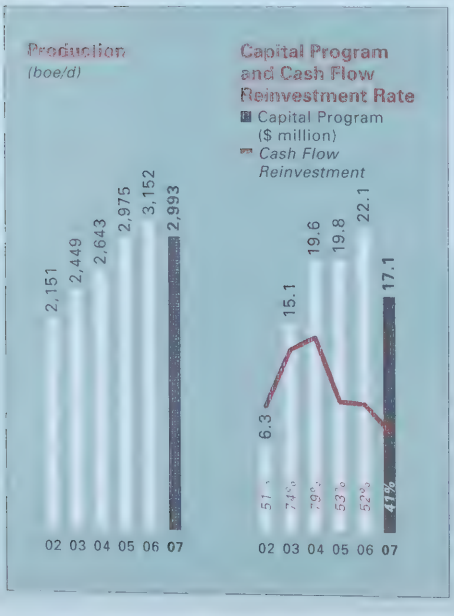
The following table identifies 20 Williston Basin waterflood exploitation projects that Zargon is currently undertaking:

Williston Basin Oil Exploitation Projects

	Waterflood Projects	Zargon Working Interest (percent)	WI[1] Oil-in-Place (mmbbl)	WI Cumulative Production (mmbbl)	WI Recovery To Date (percent)	WI[2] Remaining Reserves (mmbbl)	WI Ultimate Recovery (mmbbl)	Ultimate Recovery (percent)
North Dakota								
Haas	1	98	55.0	11.1	20	3.1	14.2	26
Truro/Mackobee	2	100	22.0	2.9	13	1.6	4.5	20
Manitoba								
Daly/Virden	2	100	27.6	3.1	11	1.2	4.3	16
Saskatchewan								
Elswick	3	95	13.2	1.5	11	0.9	2.4	18
Frys	2	100	11.0	1.4	13	0.4	1.8	16
Midale	1	97	7.9	1.1	14	0.3	1.4	18
Pinto	2	100	8.4	0.9	11	0.5	1.4	17
Steelman	2	89	11.8	1.7	14	0.9	2.6	22
Weyburn North	3	74	26.3	3.9	15	1.2	5.1	19
Workman/Carnduff	2	54	15.6	2.5	16	0.9	3.4	22
Total	20		198.8	30.1	15	11.0	41.1	21

1. *As estimated by Zargon's management.*
2. *Represents 2007 year end remaining proved and probable reserves as estimated by McDaniel & Associates Consultants Ltd.*

These 20 waterflood projects, which represent 83 percent of Zargon's Williston Basin reserves, are in various stages of implementation and are estimated to contain 199 million barrels of oil-in-place attributed to Zargon's working interests. Based on the year end 2007 McDaniel & Associates Consultants Ltd. proved and probable reserve assignment, these properties are predicted to recover an average of 21 percent of their original oil-in-place. Going forward, Zargon will continue to reinvest considerable time and capital to improve these ultimate recovery factors through a multi-year program of exploitation drilling and waterflood modifications.



In 2007, Zargon drilled 5.5 net horizontal wells and 3.1 net vertical wells in the Williston Basin, resulting in 8.6 net oil wells. The Trust also shot a 12.5 kilometre 2D seismic program at Pinto,

2008 Williston Basin Key Initiatives

- Continue the historically successful exploitation and development programs on our significant Williston Basin oil-in-place resource base through ongoing programs of seismic, waterflood modifications and exploitation drilling.
- Efficiently execute a $13 million capital program, which includes drilling approximately eight net wells at Elswick, Pinto, Ralph, Steelman and Weyburn, Saskatchewan.
- Offset production declines and maintain Williston Basin production levels at 2,900 barrels of oil equivalent per day.
- Continue to develop the organizational capability to accelerate the exploitation of this large opportunity base.

Saskatchewan. In addition to the exploitation and development drilling activities, the 2007 drilling program included 3.0 net vertical wells at Antler and Pinto that explored for Torquay and Midale targets.

In 2007, the Williston Basin area generated $41.57 million of property cash flow, of which $17.06 million, or 41 percent, was reinvested in the core area. Reflecting this reduced 2007 reinvestment rate, the Williston Basin production volumes declined five percent to 2,993 barrels of oil equivalent per day in 2007. The reduced capital program also impacted the Williston Basin reserves, which showed a four percent decrease in the year end proved and probable reserves to 13.26 million barrels of oil equivalent. The reserves were also impacted by a year end 327 thousand barrels of oil equivalent reduction in proved and probable reserves at the Haas, North Dakota property due to increased water encroachment at certain vertical wells. The net result was that the 2007 Williston Basin capital programs delivered a proved and probable reserve finding and development costs at $38.58 per barrel of oil equivalent, a cost that was more than twice the previous year's.

Over the last few months, Zargon has reorganized its Williston Basin core area team to focus solely on its substantial oil exploitation opportunities. These projects are time consuming as reservoir models are constructed, waterflood applications are submitted, facilities are modified, water injections are commenced, reservoir pressures are monitored and, eventually, horizontal drainage wells are drilled. To improve this core area's returns, exploration projects for Torquay, Bakken and Frobisher/Midale targets have been set aside. Going forward, Zargon has a very large inventory of exploitation opportunities that should provide stable or growing core area production volumes for many years to come.

Williston Basin

	2007	2006	2005	2004	2003
Average Production					
Oil and liquids (bbl/d)	**2,946**	3,117	2,935	2,603	2,387
Natural gas (mmcf/d)	**0.28**	0.22	0.24	0.26	0.37
Equivalents (boe/d)	**2,993**	3,152	2,975	2,643	2,449
Total Proved & Probable Reserves[1]					
Oil and liquids (mbbl)	**12,829**	13,452	12,942	11,930	11,105
Natural gas (bcf)	**2.59**	2.45	1.01	0.98	0.86
Equivalents (mboe)	**13,262**	13,861	13,110	12,093	11,248
Undeveloped Lands					
Net acres (thousands)	**68.7**	58.6	48.6	45.1	39.4
Drilling Activities					
Net wells	**8.6**	22.0	14.3	7.5	8.0
Core Area Cash Flow ($ million)	**41.57**	42.55	37.12	25.37	20.37
Capital Expenditures ($ million)					
Net property and corporate acquisitions/ (dispositions)	**0.47**	(3.14)	2.26	10.82	6.10
Undeveloped land, seismic and geological	**1.89**	2.80	1.51	1.24	2.13
Drilling and completions	**10.86**	17.28	12.54	4.91	4.86
Equipping and facilities	**3.84**	5.19	3.53	2.61	2.00
Total expenditures	**17.06**	22.13	19.84	19.58	15.09
Capital Program Efficiencies					
Finding, development and acquisition costs ($/boe)[2]	**38.58**	15.99	8.78	11.76	6.66

1. *Proved and probable reserves are trust working interest reserves before royalties (6:1).*
2. *The reported proved and probable finding, development and acquisition ("FD&A") costs include an allowance for the change in future capital expenditures. This calculation also includes allowances for prior year reserve revisions and the 2003 reserve definition changes relating to National Instrument 51-101 Standards of Disclosure.*

Activity Review

HIGHLIGHTS

Zargon had an active year in 2007, spending $66.67 million on capital programs that included the drilling of 46.9 net wells, the completion of 47.1 net wells, the acquisition of 51 thousand net acres of Crown undeveloped land, the shooting of 165 kilometres of 2D seismic, the construction of 33 net kilometres of pipelines, the tie-in of 47.2 net wells and the conclusion of five small property transactions. In addition to supporting Zargon's $2.16 per trust unit distributions, these capital expenditures provided a two percent gain in average daily production volumes.

	2007	2006	Percent Change
Total net capital expenditures ($ million)	**66.67**	63.37	5
Undeveloped land (thousand net acres)	**362**	381	(5)
Wells drilled, net	**46.9**	76.2	(38)
Total production (boe/d)	**8,560**	8,422	2
Year end proved and probable reserves (mmboe)	**26.91**	27.46	(2)

LAND AND SEISMIC

In 2007, Zargon spent $7.49 million (including capitalized lease rentals on non-producing properties) on replenishing its undeveloped land base. This total was 43 percent higher than the $5.25 million spent in 2006. During the year, Zargon purchased 51 thousand net Crown acres primarily consisting of natural gas prospective Alberta Crown lands for a total cost of $4.23 million or $82 per acre. Previously, Zargon had acquired 42 thousand net acres in 2006 and 31 thousand net acres in 2005 at average costs of $88 and $113 per acre, respectively. In addition to the 2007 Crown purchases, Zargon spent $1.00 million on a 2007 freehold leasing program adding 11 thousand net acres of undeveloped land.

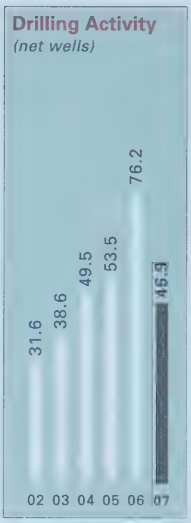
Zargon's undeveloped land inventory decreased five percent in 2007 to 362 thousand net acres. This decline resulted from increased 2007 undeveloped land expiries compared to 2006 that were only partially offset by the Crown and freehold leasing programs. In 2008, Zargon anticipates undeveloped land expiries of approximately 80 thousand net acres and, of these land expiries, a significant percentage will be replenished by Crown and freehold land acquisitions or from corporate acquisitions.

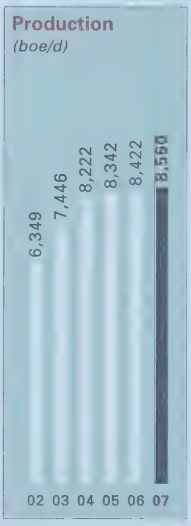
The independent firm of Seaton-Jordan & Associates Ltd. ("Seaton-Jordan") has valued Zargon's 356 thousand net acres of Canadian undeveloped land holdings, as of December 31, 2007, at $42.86 million, and Zargon has performed an internal valuation of its six thousand net acres of United States undeveloped land at $0.29 million for a total value of undeveloped land of $43.15 million, a one percent decrease in value over last year's $43.55 million appraisal. This analysis reflects an average value of $119 per acre that compares to $114 per acre average in 2006.

As part of its continuing exploration effort, Zargon shot 165 kilometres of 2D seismic in 2007. Of this amount, approximately 94 kilometres were shot at the Jarrow property in the Alberta Plains core area and approximately 31 kilometres at the Highvale property in the West Central Alberta core area as Zargon continued to assess its considerable inventory of land and natural gas prospects in these areas. Total geological and geophysical costs in 2007 were $4.41 million, which is 32 percent higher than the prior year's geological and geophysical expenditures of $3.34 million primarily due to an increased seismic program in the Alberta Plains and West Central Alberta core areas.

DRILLING, COMPLETIONS AND WORKOVERS

Reflecting both a smaller Alberta Plains gas development program and reduced Williston Basin and Pembina exploration programs, Zargon drilled 46.9 net wells in 2007, a 38 percent decrease in drilling activity from 2006 and a 12 percent decrease from 2005. The 2007 drilling program resulted in 11.6 net oil wells, 32.7 net natural gas wells and 2.6 net dry holes. Zargon's success ratio was 94 percent in the 2007 drilling program, a decrease of one percent from the 95 percent success ratio in 2006.



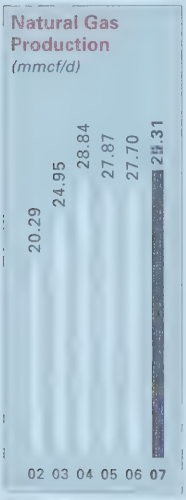


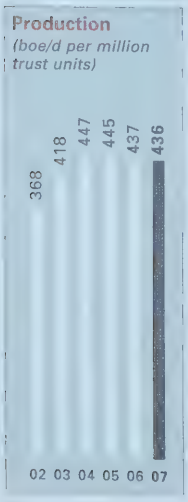
DRILLING ACTIVITY

(Number of Wells)	2007		2006		2005	
	Gross	**Net**	Gross	Net	Gross	Net
Oil	**14**	**11.6**	26	22.5	15	13.5
Natural gas	**36**	**32.7**	57	47.7	40	35.3
Water injector	**–**	**–**	2	2.0	1	0.9
Dry	**3**	**2.6**	4	4.0	4	3.8
Total	**53**	**46.9**	89	76.2	60	53.5
Exploratory	**20**	**17.7**	30	28.8	25	23.0
Development	**33**	**29.2**	59	47.4	35	30.5
Total	**53**	**46.9**	89	76.2	60	53.5
West Central Alberta	**7**	**6.2**	16	14.7	16	14.1
Alberta Plains	**35**	**32.1**	48	39.5	28	25.1
Williston Basin	**11**	**8.6**	25	22.0	16	14.3
Total	**53**	**46.9**	89	76.2	60	53.5
Average Zargon Working Interest	**89%**		86%		89%	

During 2007, Zargon operated the drilling of 50 gross wells with an average working interest of 93 percent. Zargon's minor participation in an additional three non-operated wells brought Zargon's average working interest to 89 percent. Similar to recent years, the drilling program was primarily weighted to Alberta natural gas targets with 82 percent of the net wells drilled in the Alberta Plains and West Central Alberta core areas compared to 71 percent in 2006. In 2008, Zargon is planning to drill 45 net wells with about 65 percent of these wells focused on natural gas exploration and development and oil exploitation in the Alberta Plains core area. The remainder of the program will be equally divided between West Central Alberta natural gas exploration projects and Williston Basin oil exploitation projects.

In 2007, expenditures for drilling, completion and workovers totalled $33.15 million, a 21 percent decrease from the $41.80 million spent in 2006. Drilling related expenditures were lower due primarily to Zargon's reduced activity levels. The 2007 program also included the completion of 47.1 net wells.





PRODUCTION EQUIPMENT AND FACILITIES

In 2007, Zargon spent $18.49 million, a 16 percent increase over the prior year's level, on production equipment and facilities, which included gas plant expansions, oil battery modifications, the construction of approximately 33 net kilometres of pipelines, the tie-in of 47.2 net wells and the buy-out acquisition of $2.54 million of existing compressor leases. Approximately 53 percent of these costs were incurred in Alberta Plains, 26 percent in West Central Alberta and 21 percent in Williston Basin core areas.

PROPERTY ACQUISITIONS

Zargon's net property acquisitions totalled $1.86 million in 2007, compared to $3.14 million of net property dispositions in 2006. During 2007, Zargon completed four property acquisitions and one property disposition that were related to existing core area properties. In 2006, the dispositions related primarily to the $3.70 million sale of two small higher operating cost, non-core oil properties in the Williston Basin core area having a combined production of 60 barrels per day of oil.

PRODUCTION

Natural gas sales volumes increased six percent in 2007 to average 29.31 million cubic feet per day, compared to 27.70 million cubic feet per day in 2006 (2005 – 27.87 million cubic feet per day). The increase in natural gas production was primarily due to the addition of volumes from the development programs at Jarrow and Hamilton Lake in the Alberta Plains core area and the tie-in of wells in 2007 from a successful 2006 drilling program in the West Central Alberta core area. Crude oil and natural gas liquid sales volumes decreased three percent in 2007 to 3,675 barrels per day, compared to 3,805 barrels per day in 2006 (2005 – 3,697 barrels per day). This production decline resulted primarily from a reduced level of activity being insufficient to offset natural declines primarily in the Williston Basin.

Zargon's 2007 average daily production increased two percent to 8,560 barrels of oil equivalent per day compared to 8,422 barrels of oil equivalent per day in 2006 (2005 – 8,342 barrels of oil equivalent per day). On a production per total trust unit basis, Zargon produced 436 barrels of oil equivalent per day per million units in 2007, essentially unchanged from the 2006 levels of 437 barrels of oil equivalent per day per million units. During the year, natural gas production represented 57 percent of total volumes, a slight increase from the 55 percent weighting in 2006.

RESERVES

Formal disclosure of oil, natural gas liquids and natural gas reserves as required by National Instrument 51-101 Standards of Disclosure ("NI 51-101") will be included in the Trust's Annual Information Form for the year ended December 31, 2007 that will be filed on SEDAR.

Since 1993, the independent engineering firm of McDaniel & Associates Consultants Ltd. ("McDaniel") has evaluated 100 percent of Zargon's reserves. Commencing with the 2003 year end report, Zargon's reserve estimates have been calculated in accordance with NI 51-101. Under NI 51-101, proved reserve estimates are defined as having a 90 percent probability that actual reserves recovered over time will equal or exceed proved reserve estimates. Probable reserves are defined under NI 51-101 so that there are equal (50 percent) probabilities that the actual reserves to be recovered will be less than, or greater than, the proved and probable reserves estimate.

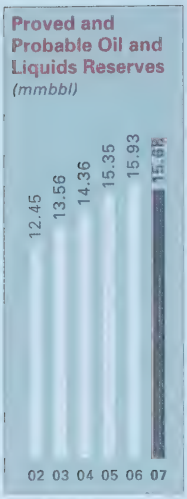
In a report dated February 28, 2008, McDaniel assigned the following reserve estimates based on forecast prices and costs as of December 31, 2007:

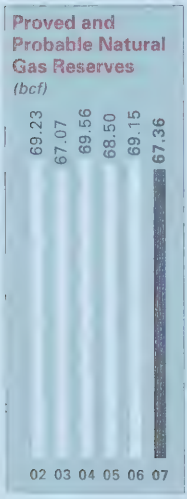
Trust Reserves[1]

At December 31, 2007	Oil and Liquids (mmbbl)	Natural Gas (bcf)	Equivalents[2] (mmboe)
Proved producing	11.04	36.80	17.17
Proved non-producing	0.07	6.75	1.20
Proved undeveloped	0.32	0.31	0.37
Total proved	**11.43**	**43.86**	**18.74**
Probable additional	4.25	23.50	8.17
Total proved and probable	**15.68**	**67.36**	**26.91**
Proved producing reserve life index, years	8.3	3.3	5.4
Proved reserve life index, years	8.5	3.9	5.8
Proved and probable reserve life index, years	11.7	6.0	8.4

1. *Trust working interest reserves before royalties, boe (6:1).*
2. *Boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.*

In McDaniel's report, proved producing reserves represented 92 percent of Zargon's total proved reserves while total proved reserves accounted for 70 percent of proved and probable reserves. These percentages compare to the respective 86 and 69 percentages reported in the 2006 year end report. Zargon's proved non-producing reserves are comprised primarily of natural gas reserves from recently drilled wells at the Alberta Plains core area property of Jarrow and selected West Central Alberta core area properties. McDaniel forecasts $10.84 million of net future (forecast prices) capital costs to deliver the total proved reserve estimate. Zargon's probable reserves generally reflect incremental waterflood recoveries on producing oil properties and improved gas recoveries for currently producing natural gas wells. McDaniel forecasts $24.42 million of net future (forecast prices) capital costs to deliver the total proved and probable reserve estimate.





Based on 2007 year end reserves and Zargon's 2007 fourth quarter production rates of 3,666 barrels of oil and liquids per day and 30.74 million cubic feet of natural gas per day, Zargon's proved reserve life index is 8.5 years for oil and liquids, 3.9 years for natural gas and 5.8 years on an oil equivalent basis. The corresponding proved and probable oil and liquids, natural gas and oil equivalent reserve life indices are 11.7, 6.0 and 8.4 years, respectively. The relatively high oil and liquids reserve life reflects Zargon's portfolio of long-life shallow-decline Williston Basin waterflood projects.

RESERVE RECONCILIATION

A reconciliation of the 2007 year end reserve assignments with the reserves reported in the 2006 year end report is presented below:

Reserve Reconciliation

	Oil and Liquids (mmbbl)			Natural Gas (bcf)			Equivalents (mmboe)		
	Proved	Probable	Proved & Prob.	Proved	Probable	Proved & Prob.	Proved	Probable	Proved & Prob.
December 31, 2006	11.52	4.41	15.93	45.15	24.00	69.15	19.05	8.41	27.46
Discoveries and extensions	0.84	0.40	1.24	4.55	3.34	7.89	1.59	0.96	2.55
Revisions	0.41	(0.56)	(0.15)	4.86	(3.86)	1.00	1.22	(1.20)	0.02
Acquisitions and dispositions	–	–	–	–	0.02	0.02	–	–	–
Production	(1.34)	–	(1.34)	(10.70)	–	(10.70)	(3.12)	–	(3.12)
December 31, 2007	11.43	4.25	15.68	43.86	23.50	67.36	18.74	8.17	26.91

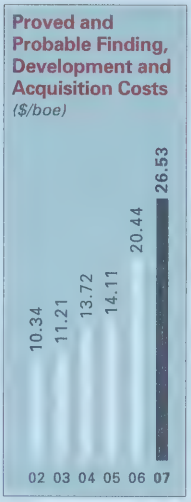
Proved reserves at December 31, 2007 decreased two percent from the prior year. Proved 2007 reserve additions were 2.81 million barrels of oil equivalent (after revisions) or 1.59 million barrels of oil equivalent (before revisions). Positive technical proved reserve revisions were 1.22 million barrels of oil equivalent, which equated to six percent of the 2007 proved reserves opening balance. Positive revisions were primarily attributed to the conversion of prior year probable reserves to proved reserves as a result of positive performance results coming from the 2007 capital programs at West Central Alberta gas properties and certain oil properties in each of the core areas.

On a proved and probable basis, Zargon's reserves decreased two percent in 2007 as the addition of 2.57 million barrels of oil equivalent (after revisions) or 2.55 million barrels of oil equivalent (before revisions) only replaced 82 percent (82 percent before revisions) of Zargon's 2007 production. Field capital exploration and development programs provided 2.55 million barrels of oil equivalent of new additions. Positive technical reserve revisions were 0.02 million barrels of oil equivalent. During the year, positive technical revisions pertaining to West Central Alberta gas properties were offset by negative production performance related reserve adjustments at the Haas, North Dakota property in the Williston Basin.

FINDING, DEVELOPMENT AND ACQUISITION COSTS

For 2007, Zargon's total proved finding, development and acquisition ("FD&A") costs, taking into account reserve revisions and changes in estimated future development capital during the period, were $22.11 per barrel of oil equivalent. For calculation purposes, the $65.40 million of 2007 net capital additions was combined with a decrease in estimated future development capital for total proved reserves of $3.27 million ($10.84 million at December 31, 2007 compared to $14.11 million at December 31, 2006). If the change in future development costs is excluded, the 2007 proved and probable FD&A costs, taking into account reserve revisions, were $23.27 per barrel of oil equivalent.

For 2007, Zargon's proved and probable finding, development and acquisition ("FD&A") costs, taking into account reserve revisions and changes in estimated future development capital during the period, were $26.53 per barrel of oil equivalent. For calculation purposes, the $65.40 million of 2007 net capital additions was combined with an increase in estimated future development capital for proved and probable reserves of $2.79 million ($24.42 million at December 31, 2007 compared to $21.63 million at December 31, 2006). If the change in future development costs is excluded, the 2007 proved and probable FD&A costs, taking into account reserve revisions, were $25.45 per barrel of oil equivalent.



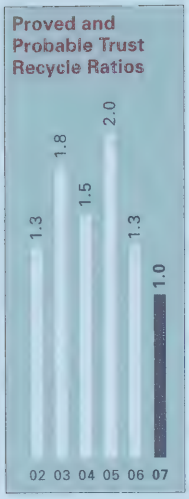
Proved and Probable Finding, Development and Acquisition Costs[1]

	2007	2006	2005
Total net capital expenditures ($ million)[2]	**65.40**	63.37	54.68
Total net capital expenditures plus change in forecast future development costs ($ million)	**68.19**	76.85	54.46
Proved and probable reserves (mmboe)			
Open	**27.46**	26.77	25.95
Discoveries and extensions	**2.55**	4.29	3.76
Acquisitions and dispositions	**–**	(0.10)	0.12
Revisions	**0.02**	(0.43)	(0.02)
Production	**(3.12)**	(3.07)	(3.04)
Close	**26.91**	27.46	26.77
Proved and probable FD&A costs ($/boe)[3]	**26.53**	20.44	14.11
Proved and probable three-year FD&A costs ($/boe)[3]	**19.58**	15.98	13.09

1. *The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.*
2. *2007 amounts exclude additions for administrative assets.*
3. *Amounts are calculated including the change in future development costs.*

Zargon experienced higher FD&A costs in 2007 due to the combination of disappointing results from certain Alberta Plains natural gas development and exploration programs, negative proved and probable reserve adjustments of 0.33 million barrels of oil equivalent at the Williston Basin Haas, North Dakota property and increased costs for essentially all field capital program activities.

In 2007, Zargon's net property acquisitions were $1.86 million. If the impact of the 2007 net acquisitions is excluded, Zargon's proved and probable finding and development ("F&D") costs including future development costs would have been $25.81 per barrel of oil equivalent (2006 – $20.72 per barrel of oil equivalent).



Capital Program Performance

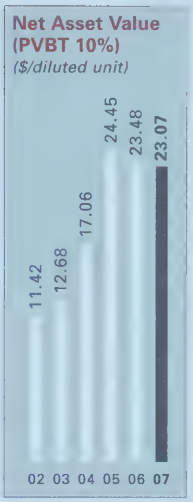
	2007	2006	2005	Three-Year Average (2005–2007)
Trust funds flow from operations ($/boe)[1]	**25.55**	26.97	27.71	26.73
Total Capital Program (excluding future development costs)				
Proved and probable FD&A costs ($/boe)[2]	**25.45**	16.85	14.17	18.00
Trust recycle ratio[3]	**1.00**	1.60	1.96	1.48
Total Capital Program (including future development costs)				
Proved and probable FD&A costs ($/boe)[2]	**26.53**	20.44	14.11	19.58
Trust recycle ratio[3]	**0.96**	1.32	1.96	1.37
Capital Program (including future development costs) **Exclusive of Net Property Acquisitions/ Dispositions and Corporate Acquisitions**				
Proved and probable F&D costs ($/boe)[2]	**25.81**	20.72	13.91	19.50
Trust recycle ratio[3]	**0.99**	1.30	1.99	1.37
Production Addition Costs				
Production addition costs ($ thousand/boe/d)[4]	**37.63**	38.40	32.76	36.27
Production addition costs – exclusive of net property acquisitions/dispositions and corporate acquisitions ($ thousand/boe/d)[4]	**39.70**	40.54	28.95	36.40

1. *Trust funds flow from operations including allowances for current taxes, interest and financing charges and general and administrative expenses on a barrel of oil equivalent production basis (6:1).*
2. *FD&A and F&D costs taking into account reserve revisions during the year on a barrel of oil equivalent basis (6:1).*
3. *Trust recycle ratio is defined as the Trust funds flow from operations per barrel of oil equivalent divided by proved and probable finding, development and acquisition costs per barrel of oil equivalent. In the case of amounts for the capital program exclusive of net acquisitions/dispositions and corporate acquisitions, the Trust funds flow per barrel of oil equivalent is divided by proved and probable finding and development costs.*
4. *The production addition costs for the total capital program are calculated by dividing the year's net capital expenditures by the year's actual change in production rate plus the year's estimated naturally occurring decline in production. This production decline is estimated as the year end proved producing (forecast case) depletion rate (the inverse of the reserve life index) based on fourth quarter production rates. The production addition costs for the capital program exclusive of net acquisitions/dispositions and corporate acquisitions are calculated on a similar basis except total capital, reserves and production are adjusted for the amounts related to net acquisitions/dispositions and corporate acquisitions.*

NET ASSET VALUE

Zargon's oil, natural gas liquids and natural gas reserves were evaluated using the McDaniel product price forecasts effective January 1, 2008, prior to provisions for income taxes, interest, debt service charges and general and administrative expenses.

It should not be assumed that the following discounted future net property cash flows estimated by McDaniel represent the fair market value of the reserves:



Before Tax Present Value of Future Net Revenue

(Forecast Price Case)

	Discount Factor			
($ million)	0%	5%	10%	15%
Proved producing	486.0	393.4	332.2	290.0
Proved non-producing	27.0	22.6	19.4	17.0
Proved undeveloped	9.0	6.3	4.6	3.5
Total proved	**522.0**	**422.3**	**356.2**	**310.5**
Probable	263.5	162.7	113.9	86.3
Total proved and probable	**785.5**	**585.0**	**470.1**	**396.8**

The above discounted future net property cash flows are based on the McDaniel price assumptions that are contained in the following table:

McDaniel Report Pricing Assumptions

(Forecast Price Case)

	West Texas Intermediate Crude Oil ($US/bbl)	Edmonton Light Crude Oil ($Cdn/bbl)	Saskatchewan Cromer Medium Crude Oil ($Cdn/bbl)	Alberta AECO Spot Natural Gas Price ($Cdn/gj)	Exchange Rate ($US/$Cdn)	Inflation Rate (percent)
2008	90.00	89.00	78.20	6.45	1.00	2.0
2009	86.70	85.70	75.30	7.00	1.00	2.0
2010	83.20	82.20	72.20	7.00	1.00	2.0
2011	79.60	78.50	69.00	7.00	1.00	2.0
2012	78.50	77.40	68.00	7.10	1.00	2.0
2013	77.30	76.20	66.90	7.30	1.00	2.0
2014	78.80	77.70	68.20	7.55	1.00	2.0
2015	80.40	79.30	69.60	7.80	1.00	2.0
2016	82.00	80.80	71.00	8.00	1.00	2.0
2017	83.70	82.50	72.50	8.25	1.00	2.0
2018	85.30	84.10	73.80	8.45	1.00	2.0
2019	87.00	85.80	75.30	8.70	1.00	2.0
2020	88.80	87.50	76.90	8.95	1.00	2.0
2021	90.60	89.30	78.40	9.20	1.00	2.0
2022	92.40	91.10	80.00	9.40	1.00	2.0
Thereafter:	Escalate at 2.0%/year	Escalate at 2.0%/year	Escalate at 2.0%/year	Escalate at 2.0%/year	1.00	2.0

The following net asset value table shows what is customarily referred to as a "produce-out" net asset value calculation under which the current value of Zargon's reserves would be produced at the McDaniel forecast future prices and costs. The value is a snapshot in time as of December 31, 2007 and is based on various assumptions including commodity prices and foreign exchange rates that vary over time. In this analysis, the present value of the proved and probable reserves is calculated at a before tax 10 percent discount rate. In the net asset value calculation, Zargon's 356 thousand net acres of Canadian undeveloped land is valued by the independent firm of Seaton-Jordan at $42.9 million and Zargon's six thousand net acres of United States undeveloped land is internally valued at $0.3 million.

Net Asset Value

As at December 31 ($ million)	**2007**	2006	2005
Proved and probable reserves (PVBT 10%)[1][2]	**470.1**	448.8	451.4
Undeveloped land[3]	**43.2**	43.6	41.7
Working capital (excluding unrealized risk management assets and liabilities)	**(5.4)**	(9.8)	(17.1)
Bank debt	**(56.9)**	(30.0)	(10.3)
Proceeds from the exercise of all trust unit rights	**39.3**	31.8	20.9
Net asset value (including trust unit rights dilution)	**490.3**	484.4	486.6
Net asset value per unit			
Total ($/unit)	**22.82**	23.30	24.53
With full dilution ($/unit)[4]	**23.07**	23.48	24.45

1 *McDaniel's estimate of future before tax cash flow discounted at PV 10 percent.*

2 *PVBT represents present value before taxes.*

3 *Seaton-Jordan year end estimates.*

4. *Full dilution of units represents the year end units outstanding plus the presumed exercise of all trust unit rights and the conversion of exchangeable shares converted at the exchange ratio at the end of the year. At December 31, 2007, Zargon had 17.076 million trust units, 2.071 million exchangeable shares and 1.488 million trust unit incentive rights issued and outstanding. Assuming conversion of exchangeable shares at the effective exchange ratio at year end of 1.29611 and the exercise of all trust unit incentive rights, there would be 21.249 million trust units outstanding at this date.*

TRUST SUSTAINABILITY

With the conversion during 2004 to a trust, Zargon's objectives are to sustain distributions, production and reserves on a per unit basis.

The following is a summary of the key metrics that Zargon monitors as it works towards meeting its sustainability objectives:

Key Sustainability Metrics

	2007	2006	Percent Change
Cash distributions ($/trust unit)	**2.16**	2.16	–
Funds flow from operations ($/unit diluted)	**4.08**	4.31	(5)
Trust payout ratio (percent)	**53**	50	6
Average production (boe/d per million trust units)	**436**	437	–
Proved and probable reserves (boe/total unit)	**1.36**	1.41	(4)
Funds flow from operations ($/boe)	**25.55**	26.97	(5)
Proved and probable FD&A costs ($/boe)	**26.53**	20.44	30
Trust recycle ratio	**0.96**	1.32	(27)
Production addition costs ($ thousand/boe/d)[1]	**37.6**	38.4	(2)

1. *The production addition costs for the capital program are calculated by dividing the year's net capital expenditures by the year's actual change in production rate plus the year's estimated naturally occurring decline in production. This production decline is estimated as the year end proved producing (forecast case) depletion rate (the inverse of the reserve life index) based on fourth quarter production rates.*

Management's Discussion and Analysis

Brent C. Heagy
Executive Vice President
and Chief Financial Officer

Management's discussion and analysis ("MD&A") is a review of Zargon Energy Trust's 2007 financial results and should be read in conjunction with the audited consolidated financial statements and related notes for the years ended December 31, 2007 and 2006. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). All amounts are in Canadian dollars unless otherwise noted. All references to "Zargon" or the "Trust" refer to Zargon Energy Trust and all references to the "Company" refer to Zargon Oil & Gas Ltd.

In the MD&A, reserves and production are commonly stated in barrels of oil equivalent ("boe") on the basis that six thousand cubic feet of natural gas is equivalent to one barrel of oil. Boes may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalent conversion method primarily applicable to the burner tip and does not represent a value equivalent at the wellhead.

The following are descriptions of non-GAAP measures used in this MD&A:

- *The MD&A contains the term "funds flow from operations" ("funds flow"), which should not be considered an alternative to or more meaningful than, "cash flows from operating activities" as determined in accordance with Canadian GAAP as an indicator of the Trust's financial performance. This term does not have any standardized meaning as prescribed by GAAP and therefore, the Trust's determination of funds flow from operations may not be comparable to that reported by other trusts. The reconciliation between cash flows from operating activities and funds flow from operations can be found in the table below and in the consolidated statements of cash flows in the consolidated financial statements. The Trust evaluates its performance based on net earnings and funds flow from operations. The Trust considers funds flow from operations to be a key measure as it demonstrates the Trust's ability to generate the cash necessary to pay distributions, repay debt and to fund future capital investment. It is also used by research analysts to value and compare oil and gas trusts, and it is frequently included in published research when providing investment recommendations. Funds flow from operations per unit is calculated using the diluted weighted average number of units for the period.*

Funds Flow from Operations Reconciliation

($ million)	**2007**	2006	2005
Cash flows from operating activities	**76.30**	83.74	82.97
Changes in non-cash working capital	**3.54**	(0.85)	1.40
Funds flow from operations[1]	**79.84**	82.89	84.37

1. *Throughout this report, funds flow from operations is now inclusive of asset retirement expenditures. All prior period calculations have been restated to reflect this change.*

- *The Trust also uses the term "debt net of working capital". Debt net of working capital as presented does not have any standardized meaning prescribed by Canadian GAAP and may not be comparable with the calculation of similar measures for other entities. Debt net of working capital as used by the Trust is calculated as bank debt and any working capital deficit excluding the current portion of unrealized risk management assets and liabilities.*
- *Operating netbacks equal total petroleum and natural gas revenue per boe adjusted for realized risk management gains and/or losses per boe, royalties per boe and production costs per boe. Operating netbacks are a useful measure to compare the Trust's operations with those of its peers.*
- *Funds flow netbacks per boe are calculated as operating netbacks less general and administrative expenses per boe, interest and financing charges per boe, asset retirement expenditures per boe and current income taxes per boe. Funds flow netbacks are a useful measure to compare the Trust's operations with those of its peers.*

References to "production volumes" or "production" in this MD&A refer to sales volumes.

Forward-Looking Statements – This document contains statements that are forward-looking, such as those relating to results of operations and financial condition, general economic conditions, industry conditions, changes in regulatory and taxation regimes, volatility of commodity prices, escalation of operating and capital costs, currency fluctuations, the availability of services, imprecision of reserve estimates, geological, technical, drilling and processing problems, environmental risks, weather, the lack of availability of qualified personnel or management, stock market volatility, the ability to access sufficient capital from internal and external sources and competition from other industry participants for, among other things, capital, services, acquisitions of reserves, undeveloped lands and skilled personnel. By their nature, forward-looking statements are subject to numerous risks and uncertainties that could significantly affect anticipated results in the future and, accordingly, actual results may differ materially from those predicted. The forward-looking statements contained in this document are as of March 12, 2008 and are subject to change after this date. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Zargon disclaims, except as required by law, any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events, or otherwise.

This MD&A has been prepared as of March 12, 2008.

2007 Highlights

The combination of high crude oil prices and stable production volumes enabled Zargon to achieve relatively stable revenues and funds flow from operations in 2007. During 2007, Zargon's one percent gain in revenues to $155.51 million came primarily from a two percent increase in production volumes and a six percent gain in oil and liquid prices that was partially offset by a six percent decrease in natural gas prices. Zargon's 2007 funds flow from operations showed a four percent decline to $79.84 million, as Zargon experienced higher production, general and administrative and interest and financing costs in the year. Net earnings for the year were $24.55 million, a 45 percent decrease from 2006. The majority of the changes in the net earnings came from large changes in the non-cash items pertaining to unrealized risk management gains/losses and future income taxes.

Net capital expenditures for 2007 totalled $66.67 million with $63.54 million allocated to field-related activities, $1.86 million to net property acquisitions and $1.27 million to administrative assets. Compared to the prior year, the 2007 capital program showed a five percent increase in overall net expenditures and a four percent decrease in field-related expenditures. For the year ended December 31, 2007, Zargon spent $7.49 million to maintain an undeveloped land base of 362 thousand net acres (2006 – 381 thousand net acres); shot or acquired seismic at a cost of $4.41 million; drilled, equipped and tied-in wells for $51.64 million and concluded $1.86 million of net property acquisitions. Cash distributions to unitholders totalled $36.70 million during the 2007 year (2006 – $35.90 million). All of these activities were funded by the year's funds flow plus an increase in debt net of working capital (excluding the unrealized risk management assets and liabilities) of $22.48 million.

Financial Highlights

($ million, except per unit amounts)	2007	2006	2005
Petroleum and natural gas revenue	**155.51**	154.04	162.72
Funds flow from operations[1]	**79.84**	82.89	84.37
Per unit – diluted	**4.08**	4.31	4.48
Net earnings	**24.55**	44.50	35.37
Per unit – diluted	**1.45**	2.68	2.19
Total assets	**340.19**	310.57	277.86
Net capital expenditures[2]	**66.67**	63.37	54.68
Bank debt	**56.87**	30.04	10.34
Cash distributions	**36.70**	35.90	37.44

1. *Throughout this report, funds flow from operations is now calculated inclusive of asset retirement expenditures. All prior period calculations have been restated to reflect this change.*
2. *Amounts include capital expenditures acquired for cash and equity issuances.*

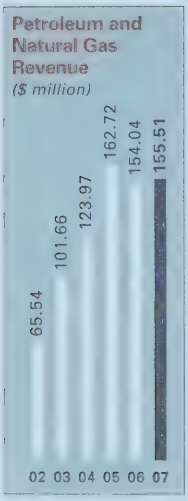
CASH DISTRIBUTIONS

Cash distributions to unitholders are at the discretion of the Board of Directors and can fluctuate depending on funds flow from operations. The Trust's capital program is financed from available funds flow and additional draw downs on the bank facilities, if required. The key drivers of Zargon's funds flow are commodity prices and production volumes. Since the Trust's production is relatively evenly weighted between natural gas (2007 – 57 percent) and oil and liquids (2007 – 43 percent), both commodity prices have a significant effect on its funds flow. In the event that oil and natural gas prices and/or production volumes are higher than anticipated and a cash surplus develops, the surplus may be used to increase distributions, reduce debt, and/or increase the capital program. In the event that oil and natural gas prices

and/or production volumes are lower than expected, the Trust may decrease distributions, increase debt and/or decrease the capital program. Zargon regularly reviews its monthly distribution policy in the context of the current commodity price environment, production levels and capital program requirements. Distributions remained constant throughout 2007 at $0.18 per trust unit and have been maintained at this level since November 2005. Cash distributions to unitholders declared for 2007 totalled $36.70 million. For a further discussion, see the "Liquidity and Capital Resources" section of this report.

For Canadian income tax purposes, the 2007 cash distributions are 100 percent taxable income to unitholders.

Detailed Financial Analysis

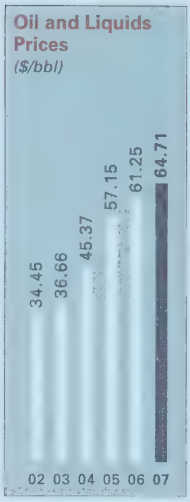


PETROLEUM AND NATURAL GAS REVENUE

Zargon derives its revenue from the production and sale of petroleum (oil, natural gas liquids) and natural gas. Petroleum and natural gas revenue, exclusive of the impact of financial risk management contracts, increased one percent to $155.51 million in 2007 from $154.04 million in 2006 primarily due to a slight increase in overall production. Compared to the prior year, the relative weighting of production revenue between petroleum and natural gas in 2007 was reallocated due to commodity pricing with 56 percent of the revenues coming from the sale of oil and liquids (55 percent in 2006) and 44 percent coming from the sale of natural gas (45 percent in 2006). Production volumes on a barrel of oil equivalent basis in 2007 increased two percent to 8,560 barrels of oil equivalent per day from the prior year amount of 8,422 barrels of oil equivalent per day. Specifically, in 2007, natural gas production increased six percent and oil and liquids production decreased three percent over 2006 levels. Production decreases in oil and liquids resulted primarily from Williston Basin natural declines. Natural gas production increases resulted from the ongoing development program in Zargon's Jarrow and Hamilton Lake areas and from the tie-in of the West Central Alberta core area wells drilled as part of the 2006 drilling program. The average price of oil and liquids received by Zargon rose to $64.71 per barrel in 2007, up six percent from 2006. The average field price of natural gas was $6.40 per thousand cubic feet in 2007, a six percent decrease from $6.82 per thousand cubic feet in 2006.

Pricing

Average for the year	2007	2006	2005
Natural Gas:			
NYMEX average daily spot price ($US/mmbtu)	**6.98**	6.75	8.89
AECO average daily spot price ($Cdn/mmbtu)	**6.45**	6.54	8.77
Zargon realized field price before the impact of financial risk management contracts ($Cdn/mcf)	**6.40**	6.82	8.41
Zargon realized field price before the impact of physical and financial risk management contracts ($Cdn/mcf)	**6.26**	6.43	8.49
Zargon realized field price after the impact of physical and financial risk management contracts ($Cdn/mcf)	**6.82**	7.21	8.16
Crude Oil:			
WTI ($US/bbl)	**72.31**	66.22	56.56
Edmonton par price ($Cdn/bbl)	**76.35**	72.77	68.72
Zargon realized field price before the impact of financial risk management contracts ($Cdn/bbl)	**64.71**	61.25	57.15
Zargon realized field price after the impact of financial risk management contracts ($Cdn/bbl)	**64.54**	58.05	53.32



PETROLEUM (OIL AND NATURAL GAS LIQUIDS) PRICING

Zargon's field oil and natural gas liquids prices are adjusted at the point of sale for transportation charges and oil quality differentials from an Edmonton light sweet crude price that varies with world commodity prices. In 2007, Zargon's average oil and liquids field price, exclusive of the impact of financial risk management contracts, increased six percent to $64.71 per barrel from $61.25 per barrel in 2006 and $57.15 per barrel in 2005. The field price differential for Zargon's average blended 30 degree API crude stream was $11.64 per barrel less than the 2007 Edmonton reference crude price, which compares to the 2006 differential of $11.52 per barrel and the 2005 differential of $11.57 per barrel. As the quality and weight of Zargon's crude stream has remained relatively consistent for several years, the movements in Zargon's price differential are derived from the North American refinery supply and demand factors for light and medium crudes.

NATURAL GAS PRICING

The average field natural gas price, exclusive of the impact of financial risk management contracts, for 2007 decreased to $6.40 per thousand cubic feet, which is six percent lower than the 2006 average of $6.82 per thousand cubic feet and 24 percent lower than the 2005 average of $8.41 per thousand cubic feet. Historically, Zargon's field prices have shown a small discount to the benchmark AECO average daily price due to a lower heating content for Zargon's natural gas and due to legacy aggregator and other contracts, which are based partially on monthly index prices that tend to lag the AECO average daily index price in upward or downward trending markets. The 2007 field price differential for Zargon's natural gas before the impact of physical and financial risk management contracts was a discount of $0.19 per thousand cubic feet. In 2007, the various fixed price physical contracts, which are treated as part of natural gas production revenue and natural gas pricing, created a gain of $1.14 million (2006 – $2.51 million), equivalent to an increase of $0.11 per thousand cubic feet (2006 – $0.25 per thousand cubic feet).

Similar to the prior year, approximately 21 percent of Zargon's 2007 natural gas production was sold under aggregator contracts pursuant to long term contracts. The remainder of Zargon's natural gas production was sold by spot sale contracts and Alberta index prices were received.

RISK MANAGEMENT ACTIVITIES

Zargon's commodity price risk management policy, which is approved by the Board of Directors, allows the use of forward sales and costless collars for a targeted range of 20 to 35 percent of oil and natural gas working interest production volumes, in order to partially offset the effects of large commodity price fluctuations. Because our risk management strategy is protective in nature and is designed to guard the Trust against extreme effects on funds flow from sudden falls in prices and revenues, upward price spikes tend to produce overall losses. Financial risk management contracts in place as at December 31, 2004, were designated as hedges for accounting purposes and the Trust monitored these contracts in determining the continuation of hedge effectiveness. As at June 30, 2006, all designated hedge contracts had expired. For the designated hedge contracts, realized gains and losses were recorded in the statements of earnings as the contracts settled and no unrealized gain or loss was recognized.

For 2007, the total realized risk management gain was $4.26 million; compared to a loss of $0.57 million in 2006 and a loss of $7.75 million in 2005. Of the 2007 gain, $4.49 million (equivalent to an increase of $0.42 per thousand cubic feet) is related to a gain from natural gas financial risk management transactions slightly offset by $0.23 million (equivalent to a decrease of $0.17 per barrel) related to losses from oil financial risk management transactions. Oil swaps and collars are settled against the NYMEX pricing index, whereas natural gas swaps, collars and puts are settled against the AECO monthly pricing index. In 2007, NYMEX WTI crude oil prices generally increased throughout the year, peaking in the month of November. AECO natural gas prices trended downwards during the first nine months of 2007 with a slight recovery in the 2007 fourth quarter. For financial risk management contracts entered into after December 31, 2004, the Trust considers these contracts to be effective on an economic basis but has decided not to designate these contracts as hedges for accounting purposes, and accordingly, for these contracts, an unrealized gain or loss is recorded based on the fair value (mark-to-market) of the contracts at year end. The 2007 net unrealized risk management loss totalled $16.80 million which, compares to a $9.55 million net unrealized risk management gain in 2006 (2005 – $3.76 million loss). Specifically, the 2007 net unrealized risk management losses resulted from financial oil contract losses ($15.09 million) and financial natural gas contract losses ($1.71 million). These unrealized risk management gains or losses are generated by the change over the reporting period in the mark-to-market valuation of Zargon's future financial contracts. Gains or losses on fixed price physical contracts are included in petroleum and natural gas revenue when settled in the statements of earnings and comprehensive income and no mark-to-market valuation is recorded on these contracts.

As at December 31, 2007, the Trust had the following outstanding commodity price risk management contracts:

Financial Risk Management Contracts

	Rate	Weighted Average Price	Range of Terms
Oil swaps	300 bbl/d	$66.70 US/bbl	Jan. 1/08–Mar. 31/08
	300 bbl/d	$61.72 US/bbl	Jan. 1/08–Jun. 30/08
	600 bbl/d	$71.54 US/bbl	Jan. 1/08–Dec. 31/08
	500 bbl/d	$87.58 US/bbl	Jan. 1/08–Jun. 30/09
	300 bbl/d	$68.29 US/bbl	Apr. 1/08–Jun. 30/08
	600 bbl/d	$68.94 US/bbl	Jul. 1/08–Dec. 31/08
	500 bbl/d	$72.74 US/bbl	Jan. 1/09–Mar. 31/09
	500 bbl/d	$85.30 US/bbl	Jul. 1/09–Dec. 31/09
Natural gas swaps	6,000 gj/d	$8.41/gj	Jan. 1/08–Mar. 31/08
	1,000 gj/d	$7.84/gj	Apr. 1/08–Oct. 31/08

Physical Risk Management Contract

	Rate	Weighted Average Price	Range of Terms
Natural gas fixed price	1,000 gj/d	$7.95/gj	Apr. 1/08–Oct. 31/08

ROYALTIES

Royalties include payments made to the Crown, freehold owners and third parties. Reported royalties also include the cost of the Saskatchewan Resource Surcharge ("SRC") and the cost of North Dakota state taxes. During 2007, total royalties were $32.75 million, a decrease of two percent from $33.43 million in 2006. Royalties as a percentage of gross revenue were 21.1 percent in 2007 compared to 21.7 percent in 2006 and 22.9 percent in 2005. On a commodity basis, natural gas royalties averaged 20.9 percent in 2007, a slight increase from the previous year's average of 20.8 percent. Oil royalties averaged 21.2 percent, down slightly from the prior year 2006 rate of 22.4 percent. The decrease in oil royalties is primarily related to initial low royalty rate incentives on certain new oil production wells in Saskatchewan.

During 2007, 59 percent (2006 – 60 percent) of the total royalties were paid to provincial and state governments, with the remainder paid to freehold owners and other third parties. The SRC charges were $1.10 million in 2007, up slightly from $1.01 million in the prior year and from $1.03 million in 2005, reflecting the trend in Saskatchewan oil revenues. North Dakota state taxes decreased to $2.01 million in 2007 from $2.27 million in the prior year primarily due to decreased oil production and sales. Through to the end of 2008, Zargon expects that its royalty rate will remain stable at recent levels in the 21 to 22 percent range. During the third quarter of 2006, the Alberta Provincial Government announced the elimination of the Alberta Royalty Credit effective January 1, 2007. The estimated impact of this announcement is an increase of royalty expense of approximately $0.50 million per year for fiscal years commencing in 2007. Additionally, commencing in 2009, the oil and natural gas royalty structure will change on Alberta related production volumes. Further discussion regarding this issue is provided later in this report.

PRODUCTION EXPENSES

Zargon's production expenses increased 23 percent to $32.62 million in 2007 from $26.42 million in 2006. On a per unit of production basis, production expenses increased 22 percent to $10.44 per barrel of oil equivalent from $8.59 in 2006 ($7.89 in 2005).

Natural gas production expenses in 2007 rose 25 percent to $1.31 per thousand cubic feet from $1.05 per thousand cubic feet in 2006. The primary reasons for the increase are due to increased third-party gas gathering charges, increased third-party gas processing fees and increased water disposal and water hauling costs. These increased costs reflect, in part, the impact of additional natural gas volumes being processed through non-operated third party natural gas gathering and processing facilities.

Oil production expenses also rose in 2007 to $13.89 per barrel, an increase of 22 percent from $11.40 per barrel in 2006. The primary reasons for the increase are due to increased workovers and seasonal repairs and maintenance in the Williston Basin core area and are reflective of a continuing industry-wide trend to higher oil property operating costs, particularly in the Williston Basin.

In 2007, 2006 and 2005, Zargon's costs increased substantially due, in general, to the effect of industry-wide production cost inflation pressures, which may now be somewhat abating due to lower industry activity levels in response to recent natural gas price declines and Alberta royalty rate uncertainties. This trend culminated with a $10.51 per barrel of oil equivalent operating cost in the fourth quarter of 2007 following a record $10.95 per barrel of oil equivalent operating cost in the 2007 third quarter. For 2008, Zargon anticipates that production costs can be maintained in the $10.50 to $11.50 per barrel of oil equivalent range as general cost inflation pressures are reduced and benefits from Zargon's specific cost containment initiatives including the buyout of natural gas compressor lease contracts are realized.

OPERATING NETBACKS

The average oil and liquids price received, after realized risk management losses, in 2007 of $64.54 per barrel was 11 percent higher than the $58.05 per barrel received in 2006, while the average natural gas price received, after realized risk management gains/losses, in 2007 of $6.82 per thousand cubic feet was five percent below the $7.21 per thousand cubic feet received in 2006. Operating netbacks increased/decreased commensurately. Oil and liquids netbacks rose 12 percent to $36.93 per barrel from $32.93 per barrel in 2006. Natural gas netbacks decreased 12 percent to $4.17 per thousand cubic feet from $4.73 per thousand cubic feet in 2006. On a barrel of oil equivalent basis, 2007 operating netbacks declined less than one percent to $30.21 from $30.46 in 2006.

Operating Netbacks

	2007		2006	
	Oil and Liquids ($/bbl)	**Natural Gas ($/mcf)**	Oil and Liquids ($/bbl)	Natural Gas ($/mcf)
Production revenue	**64.71**	**6.40**	61.25	6.82
Realized risk management gain/(loss)	**(0.17)**	**0.42**	(3.20)	0.38
Royalties	**(13.72)**	**(1.34)**	(13.72)	(1.42)
Production costs	**(13.89)**	**(1.31)**	(11.40)	(1.05)
Operating netbacks	**36.93**	**4.17**	32.93	4.73

GENERAL AND ADMINISTRATIVE EXPENSES

Gross general and administrative costs increased 14 percent in 2007 to $11.69 million from $10.25 million in 2006. On a per unit of production basis, net general and administrative costs increased 16 percent to $2.63 per barrel of oil equivalent compared to $2.27 per barrel of oil equivalent in 2006 and $1.99 in 2005. Trending upwards from 2005 and 2006, the 2007 increased general and administrative costs on a per unit of production basis were due to additional office lease costs and the costs related to the expansion of Zargon's technical staff and consultants.

General and Administrative Expenses

($ million, except as noted)	**2007**	2006	2005
Gross general and administrative expenses	**11.69**	10.25	8.96
Overhead recoveries	**(3.48)**	(3.28)	(2.91)
Net general and administrative expenses	**8.21**	6.97	6.05
Net expense after recoveries ($/boe)	**2.63**	2.27	1.99
Number of office employees at year end	**45**	43	39

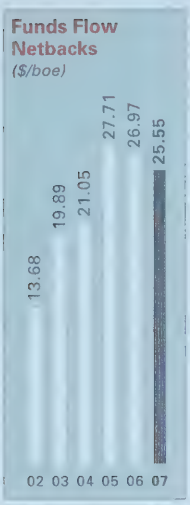
INTEREST AND FINANCING CHARGES

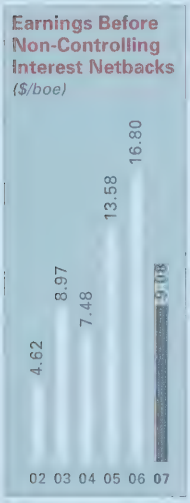
Zargon's borrowings are through its syndicated bank credit facilities. Interest and financing charges were $3.07 million compared to $1.53 million in 2006 and $0.79 million in 2005. An increase in the average debt level is the primary reason for the increase in interest and financing charges. Zargon's effective interest and financing charge rate was 6.2 percent on an average bank debt of $49.86 million in 2007, compared to 6.4 percent on an average bank debt of $23.84 million in 2006 and 4.3 percent on an average bank debt of $18.17 million in 2005. At year end 2007, Zargon's bank debt, net of working capital (excluding unrealized risk management assets and liabilities), totalled $62.30 million, up 56 percent from $39.83 million at December 31, 2006.

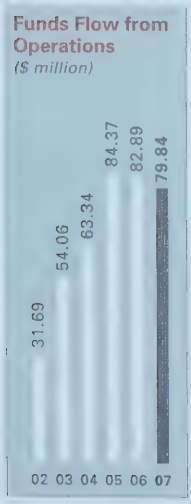
On July 30, 2007, Zargon amended and renewed its syndicated committed credit facilities, which resulted in an increase in the available facilities and borrowing base to $120 million from the previous amount of $100 million. Subsequent to year end, Zargon again amended and renewed its syndicated committed credit facilities, which resulted in a further increase in the available facilities and borrowing base to $150 million from the July 30, 2007 amount of $120 million. This most recent increase in committed credit facilities was completed on January 31, 2008 and was performed in conjunction with Zargon's corporate acquisition of Rival Energy Ltd. The next renewal date is July 29, 2008. These expanded facilities continue to be available for general corporate purposes and the potential acquisition of additional oil and gas properties such as those most recently acquired through the acquisition of Rival Energy Ltd.

CURRENT INCOME TAXES

Current income taxes for 2007 were $2.14 million compared to $1.60 million in 2006. Of the total, $2.04 million is due to current taxes incurred in the United States compared to $1.34 million in 2006. The increased 2007 taxable income in the United States is due to a reduced 2007 capital program for this geographic region, resulting in reduced tax pool claims and, therefore, resulting in higher United States taxes. Provided that oil prices remain high, a similar or slightly higher level of United States current income taxes is predicted in 2008. The remaining current tax amounts relate to Canadian provincial capital taxes, which were $0.10 million in 2007 compared to $0.26 million in 2006. Tax pools as at December 31, 2007 were approximately $148 million, which represents an increase from the comparable $113 million of tax pools available to Zargon at the end of 2006. The Trust is a taxable entity







under the Income Tax Act (Canada) and is currently only taxable (until 2011) on the income that is not distributed or declared distributable to unitholders. For Canadian income tax purposes, 2007 cash distributions are 100 percent taxable income to unitholders.

TRUST NETBACKS

Historically high oil prices and increased production volumes in 2007 resulted in relatively strong revenue netbacks and operating netbacks. On a barrel of oil equivalent basis, revenue of $49.77 in 2007 was one percent lower than the prior year and operating netbacks, as well as funds flow netbacks, decreased one percent and five percent over the prior year to $30.21 and $25.55 per barrel of oil equivalent, respectively.

Trust Netbacks

($/boe)	2007	2006	2005
Petroleum and natural gas revenue	**49.77**	50.11	53.44
Realized risk management gain/(loss)	**1.36**	(0.18)	(2.55)
Royalties	**(10.48)**	(10.88)	(12.25)
Production costs	**(10.44)**	(8.59)	(7.89)
Operating netbacks	**30.21**	30.46	30.75
General and administrative	**(2.63)**	(2.27)	(1.99)
Interest and financing charges	**(0.98)**	(0.50)	(0.26)
Asset retirement expenditures	**(0.36)**	(0.20)	(0.20)
Current income taxes	**(0.69)**	(0.52)	(0.59)
Funds flow netbacks[1]	**25.55**	26.97	27.71

1. *Throughout this report, funds flow netbacks are now calculated inclusive of asset retirement expenditures. All prior period calculations have been restated to reflect this change.*

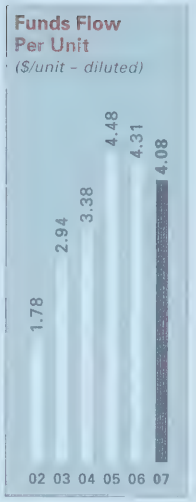
FUNDS FLOW FROM OPERATIONS *(see note at the beginning of the MD&A)*

In 2007, despite production volume increases of two percent on a barrel of oil equivalent basis and increased realized risk management gains, the overall increase in operating costs and slightly lower realized average commodity prices produced a four percent decline in funds flow from operations to $79.84 million, compared to $82.89 million in 2006 and $84.37 million in 2005. The corresponding funds flow per diluted unit was $4.08 in 2007, a five percent decline from $4.31 in 2006, and a nine percent decline from $4.48 in 2005. The diluted per unit statistics reflect a two percent increase in the weighted average outstanding units to 19.55 million in 2007 from 19.24 million in 2006. The 2006 weighted average outstanding units were also two percent higher than the 2005 amount of 18.85 million.

The following table summarizes the variances in funds flow from operations between 2006 and 2007. It demonstrates that the variance (decline in funds flow from operations) is caused mainly by a slight decrease in overall realized commodity prices and increased operating expenses, both of which were partially offset by increased production volumes, decreased royalties and increased realized risk management gains.

	$ Million	$ Per Diluted Trust Unit	Per Unit Percent Variance
Funds flow from operations - 2006[1]	**82.89**	**4.31**	–
Price variance	(1.04)	(0.05)	(1)
Volume variance	2.52	0.12	3
Realized risk management gains	4.82	0.25	6
Royalties	0.69	0.04	1
Expenses:			
Production	(6.20)	(0.32)	(7)
General and administrative	(1.24)	(0.06)	(1)
Interest and financing charges	(1.54)	(0.08)	(2)
Asset retirement expenditures	(0.51)	(0.03)	(1)
Current taxes	(0.55)	(0.03)	(1)
Weighted average trust units - diluted	–	(0.07)	(2)
Funds flow from operations - 2007	**79.84**	**4.08**	**(5)**

1. *Throughout this report, funds flow from operations is now calculated inclusive of asset retirement expenditures. All prior period calculations have been restated to reflect this change.*



DEPLETION AND DEPRECIATION

In 2007, Zargon's depletion and depreciation provision increased 18 percent to $48.41 million, compared to $41.14 million in 2006 and $37.48 million in 2005. The higher charges reflect an increase of two percent in production volumes and a 16 percent increase in the charge on a per barrel of oil equivalent basis. The primary reasons for the year-over-year expense increase on a per barrel of oil equivalent basis are due to increased finding, development and acquisition costs and the impact of the conversion of exchangeable shares relating to the application of EIC-151.

Depletion and depreciation charges calculated on a unit of production method are based on total proved reserves with a conversion of six thousand cubic feet of natural gas being equivalent to one barrel of oil. The 2007 depletion calculation includes $10.84 million of future capital expenditures to develop the Trust's reserves, but excludes $22.78 million of unproven properties relating to undeveloped land.

Zargon's depletion and depreciation, on a barrel of oil equivalent basis, increased 16 percent in 2007 to $15.49 from $13.38 in 2006 and $12.31 in 2005. Depletion and depreciation rates will be subject to continuing upward pressure as Zargon continues to experience increased finding and development costs as compared to the historical costs that were generated in prior years when commodity prices were substantially lower.

ACCRETION OF ASSET RETIREMENT OBLIGATIONS

For the year ended December 31, 2007, the non-cash accretion expense for asset retirement obligations is $1.41 million compared to $1.24 million in 2006 and $1.20 million in 2005. The year-over-year increases are due to changes in the estimated future liability for asset retirement obligations as a result of wells added through Zargon's drilling program inclusive of wells acquired/disposed of in the year and changes resulting from revisions to the timing and the amounts of the original estimates of undiscounted cash flows. The significant assumptions used in this calculation are a credit adjusted risk-free rate of 7.5 percent, an inflation rate of two percent and the payments to settle the retirement obligations occurring over the next 40 years with the majority of the costs being incurred after 2016. The estimated net present value of the total asset retirement obligation is $21.18 million as at December 31, 2007, based on a total future liability of $101.88 million.

UNIT-BASED COMPENSATION

Unit-based compensation was $1.71 million in 2007, $0.15 million lower than the $1.86 million expense in 2006. The Trust generally grants unit rights on a quarterly basis. The slight decrease in the current year expense is as a result of increased cancellations of unit rights and a general decline in the valuation of new quarterly grants. Zargon will continue to use fair value methodologies for future unit rights grants. These non-cash expenses will be recurring charges in future years if Zargon continues to grant employees and directors trust unit rights.

The trust unit rights incentive plan allows the Trust to issue rights to acquire trust units to directors, officers, employees and other service providers. The Trust is authorized to issue up to 2.36 million unit rights; however, the number of trust units reserved for issuance upon exercise of the rights shall not exceed 10 percent of the aggregate number of issued and outstanding trust units of the Trust. The Plan allows for the holder of rights to either exercise the right based on the original grant price or on a modified price as calculated per the Plan of Arrangement. Unit right grant prices are set at the market closing price for the trust units on the date prior to the unit rights being issued. Trust unit rights granted under the plan generally vest over a three-year period and expire approximately five years from the grant date.

FUTURE INCOME TAXES

The provision for the future tax recovery for 2007 was $15.47 million when compared to a future tax recovery of $2.82 million in 2006 and an expense of $0.47 million in 2005. Effectively, Zargon's future tax obligations are reduced as distributions are made from the Trust and, consequently, it is anticipated that Zargon's effective tax rate will continue to be low through to 2011. The 2007 year includes a second quarter recovery and a fourth quarter recovery relating to reductions in future federal and provincial income tax rates substantively enacted during the respective 2007 quarters. Additionally, the increase in future tax recovery, when compared to the 2006 prior year, is significantly impacted by the decrease in earnings before income taxes for the period as a result of previously mentioned items such as increased unrealized risk management losses and increased production costs.

On October 31, 2006, the Federal Government announced tax proposals pertaining to taxation of distributions paid by trusts and the personal tax treatment of trust distributions. Currently, the Trust does not pay tax on distributions as tax is paid by the unitholders. On June 12, 2007, the Federal Government enacted these tax proposals, which will result in taxation of distributions at the Trust level at a rate of 31.5 percent effective January 1, 2011. Subsequent 2007 fourth quarter legislation has lowered this tax rate to 29.5 percent in 2011 and 28.0 percent beyond 2011 to assimilate recent corporate tax rate changes. Prior to June 2007, the Trust estimated the future income tax on certain temporary differences between amounts recorded on its

balance sheet for book and tax purposes to have a nil effective tax rate. Under the legislation, the Trust now estimates the effective tax rate on the post 2010 reversal of these temporary differences to be approximately 28.0 percent. Until 2011, Zargon's future tax obligations are reduced as distributions are made from the Trust and, consequently, it is anticipated that Zargon's effective tax rate will continue to be low until that time.

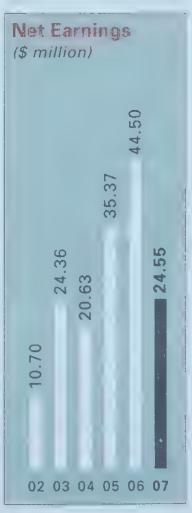
Based on its assets and liabilities as at June 30, 2007, the quarter in which the tax proposals were substantively enacted, the Trust had estimated the amount of its temporary differences, which were previously not subject to tax, and had estimated the periods in which these differences will reverse. At June 30, 2007, the Trust estimated that $7.05 million net tax deductible temporary differences will reverse after January 1, 2011, which resulted in a reduction of the future tax liability by $2.22 million in the 2007 second quarter. The taxable temporary differences relate principally to the remaining tax pools attributed to the oil and gas properties being greater than their net book value. The year-over-year increase in the future tax recovery reflects these legislated adjustments.

NON-CONTROLLING INTEREST–EXCHANGEABLE SHARES

EIC-151 "Exchangeable Securities Issued by Subsidiaries of Income Trusts", states exchangeable securities issued by a subsidiary of an Income Trust should be reflected as either a non-controlling interest or debt on the consolidated balance sheet unless they meet certain criteria. The exchangeable shares issued by Zargon Oil & Gas Ltd., a corporate subsidiary of the Trust, are publicly traded and have an expiry term, which could be extended at the option of the Board of Directors. Therefore, these securities are considered, by EIC-151, to be transferable to third parties and to have an indefinite life. EIC-151 states that if these criteria are met, the exchangeable shares should be reflected as a non-controlling interest.

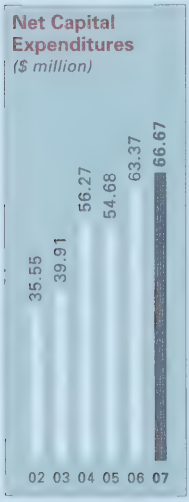
Accordingly, the Trust has increased its unitholders' equity and non-controlling interest for 2007 by $6.64 million (2006 – $12.12 million) on the Trust's consolidated balance sheets. Consolidated net earnings for 2007 have been reduced for net earnings attributable to the non-controlling interest by $3.81 million (2006 – $7.14 million). In accordance with EIC-151, and given the circumstances in Zargon's case, each redemption is accounted for as a step-purchase, which for 2007; resulted in an additional increase in property and equipment of $8.82 million (2006 – $6.73 million) and an increase in the future income tax liability of $5.99 million (2006 – $1.75 million). Funds flow from operations were not impacted by this change.

The cumulative impact to date of the application of EIC-151 has been to increase gross property and equipment by $51.76 million, (for depletion impact see note 4 in the audited consolidated financial statements), unitholders' equity and non-controlling interest by $53.35 million, future income tax liability by $17.22 million and an allocation of net earnings to exchangeable shareholders of $18.81 million.



NET EARNINGS

Zargon's 2007 net earnings were $24.55 million, a $19.95 million decrease from $44.50 million in 2006. The 2005 net earnings were $35.37 million. The net earnings track the funds flow from operations for the respective periods modified by asset retirement expenditures and non-cash charges, which in 2007; include depletion and depreciation, unrealized risk management losses, future income tax recoveries, unit-based compensation and non-controlling interest. The primary reasons for the $19.95 million decrease in net earnings when comparing the year ended 2007 to the 2006 prior year, are the previously mentioned items such as increased unrealized risk management losses ($26.35 million), increased depletion and depreciation expenses ($7.27 million) and production costs ($6.20 million) offset by realized risk management gains ($4.82 million), the related items of future tax recoveries



($12.65 million) and decreased non-controlling interest ($3.33 million). On a per diluted unit basis, 2007 net earnings were $1.45 compared to $2.68 in 2006 and $2.19 in 2005.

The 2007 net earnings were 31 percent of funds flow from operations, primarily reflecting the increase in unrealized risk management losses and the increase in future income tax recoveries. The 2006 net earnings represented 54 percent of funds flow from operations compared to 42 percent of funds flow from operations in 2005.

CAPITAL EXPENDITURES

Net capital expenditures in 2007 of $66.67 million increased five percent from $63.37 million in 2006. In 2007, Zargon completed a drilling program of 53 gross (46.9 net) wells compared to 89 gross (76.2 net) wells in 2006, and as a result drilling and completion expenditures decreased commensurately by 21 percent to $33.15 million. Of the total 2007 net capital expenditures, $18.01 million were expended on West Central Alberta, $30.33 million on Alberta Plains, $17.06 million on Williston Basin properties and $1.27 million was incurred corporately on leasehold improvements and administrative assets.

Capital Expenditures

($ million)	2007	2006	2005
Undeveloped land	**7.49**	5.25	3.65
Geological and geophysical (seismic)	**4.41**	3.34	3.47
Drilling and completion of wells	**33.15**	41.80	33.36
Well equipment and facilities	**18.49**	15.94	11.43
Exploration and development	**63.54**	66.33	51.91
Property acquisitions	**3.04**	1.40	3.68
Property dispositions	**(1.18)**	(4.54)	(2.45)
Net property acquisitions/(dispositions)	**1.86**	(3.14)	1.23
Corporate acquisitions assigned to property and equipment[1]	**–**	–	1.19
Total net capital expenditures excluding administrative assets[1]	**65.40**	63.19	54.33
Administrative assets	**1.27**	0.18	0.35
Total net capital expenditures[1]	**66.67**	63.37	54.68

1. Amounts include capital expenditures acquired for cash and equity issuances.

Subsequent Events

On January 23, 2008, Zargon completed the acquisition of Rival Energy Ltd. ("Rival") for consideration comprising 0.57 million Zargon trust units and $16.40 million in cash for all the issued and outstanding Rival common shares. Pursuant to the Rival Plan of Arrangement, Rival shareholders had the option of electing to receive 0.0562 Zargon trust units or $1.35 for each Rival common share, up to an aggregate maximum of $16.40 million in cash. The first post-Arrangement distribution by Zargon was paid on February 15, 2008 to Zargon unitholders (including former Rival shareholders who had elected to receive and continue to hold Zargon trust units) of record on January 31, 2008. In conjunction with this acquisition, Zargon also amended its credit facilities (see Bank Debt section later in this report).

On March 12, 2008, Zargon entered into an Acquisition Agreement pursuant to which Zargon has agreed to make an offer to acquire all the issued and outstanding common shares of Newpact Energy Corp. ("Newpact") and assume approximately $3.65 million of

net debt subject to a number of conditions. Pursuant to the Acquisition Agreement, Newpact shareholders will receive approximately 0.43 million Zargon trust units or approximately 0.0534 trust units for each Newpact common share.

Liquidity and Capital Resources

In 2007, the summation of the funds outflows pertaining to the net capital expenditure program ($66.67 million) and the cash distributions to unitholders ($36.70 million) exceeded the summation of the funds inflows coming from the funds flow from operations ($79.84 million) plus the proceeds from the issuance of trust units ($2.13 million) by $21.40 million.

Zargon's financing philosophy and the three sources of funding are as follows:

- Internally generated funds flow from operations provides the basic level of funding for the Trust's annual capital expenditures program and for distributions to unitholders.
- Debt may be utilized for acquisitions or to expand capital programs when it is deemed appropriate. As at December 31, 2007 the Trust had $120 million in syndicated committed credit facilities of which $63.13 million or 53 percent of these facilities are unutilized. The Trust increased these facilities by $30 million to $150 million on January 31, 2008.
- New equity, if available and if on favourable terms, can be utilized for acquisitions or to expand capital programs.

Recently, the combination of declining natural gas prices, the Alberta government's royalty announcement and the announced changes to the Canadian income trust tax rules after 2010 have partially restricted the oil and gas industry's ability to attract new capital from debt and equity markets. Zargon's historically conservative strategy of maintaining a relatively low cash distribution to funds flow ratio and conservative debt levels should enable Zargon to maintain its capital and distribution programs during this period of partially restricted access to debt and equity capital.

Cash Distributions Analysis

($ million)	**2007**	2006	2005
Cash flows from operating activities	**76.30**	83.74	82.97
Net earnings	**24.55**	44.50	35.37
Actual cash distributions paid or payable relating to the period	**(36.70)**	(35.90)	(37.44)
Excess of cash flows from operating activities over cash distributions paid	**39.60**	47.84	45.53
Excess (shortfall) of net earnings over cash distributions paid	**(12.15)**	8.60	(2.07)

Management monitors the Trust's distribution policy with respect to forecasted net cash flows, debt levels and capital expenditures. Zargon's cash distributions are discretionary to the extent that these distributions do not cause a breach of the financial covenants under Zargon's credit facilities and to the extent the Trust (non-consolidated) is not taxable. As a crude oil and natural gas Trust, Zargon's reserve base is depleted with production and Zargon, therefore, relies on ongoing exploration, development and acquisition activities to replace reserves and to offset production declines. The success of these exploration, development and acquisition capital programs, along with commodity price fluctuations are the main factors influencing the sustainability of the Trust's distributions.

For the year ended December 31, 2007, cash flows from operating activities (after changes in non-cash working capital) of $76.30 million exceeded cash distributions of $36.70 million. This was consistent with the year ended December 31, 2006 in which cash flows from operating activities (after changes in non-cash working capital) of $83.74 million exceeded cash distributions of $35.90 million.

For the year ended December 31, 2007, cash distributions of $36.70 million exceeded net earnings of $24.55 million. Net earnings include significant non-cash charges ($56.43 million in 2007) which do not impact cash flow. For the year ended December 31, 2006, cash distributions of $35.90 million were significantly less than the net earnings of $44.50 million. In the instances where distributions exceed net earnings, a portion of the cash distribution paid to unitholders may represent an economic return of the unitholders' capital.

For the year ended December 31, 2007, cash distributions and net capital expenditures totalled $103.37 million, which was $27.06 million higher than the cash flows from operating activities (after changes in non-cash working capital) of $76.30 million. For the year ended December 31, 2006, cash distributions and net capital expenditures totalled $99.27 million, which was $15.53 million higher than the cash flows from operating activities (after changes in non-cash working capital) of $83.74 million. Zargon relies on access to debt and capital markets to the extent cash distributions and net capital expenditures exceed cash flows from operating activities (after changes in non-cash working capital). Over the long term, Zargon expects to continue to fund acquisitions and growth through additional debt and equity issuances. In the crude oil and natural gas industry, because of the nature of reserve reporting, the natural reservoir declines and the risks involved in capital investment, it is not possible to distinguish between capital spent on maintaining productive capacity and capital spent on growth opportunities, therefore, maintenance capital is not disclosed separately from development capital spending.

During the year ended December 31, 2007, Zargon has maintained a monthly distribution of $0.18 per trust unit, and plans to maintain this level of distribution into 2008.

Capital Sources and Uses

($ million)	**2007**	2006	2005
Funds flow from operations[1]	**79.84**	82.89	84.37
Change in bank debt	**26.83**	19.70	(3.89)
Issuance of trust units	**2.13**	4.02	3.87
Cash distributions to unitholders	**(36.70)**	(35.90)	(37.44)
Changes in working capital and other	**(5.43)**	(7.34)	7.77
Total capital sources	**66.67**	63.37	54.68

1. *Throughout this report, funds flow from operations is now calculated inclusive of asset retirement expenditures. All prior period calculations have been restated to reflect this change.*

FUNDS FLOW FROM OPERATIONS

It is anticipated that Zargon's 2008 exploration and development capital budget and cash distributions to unitholders will be financed through the Trust's funds flow from operations and its credit facilities. Funds flow is partially influenced by factors that the Trust cannot control, such as commodity prices, the US/Canadian dollar exchange rates and interest rates. Zargon's 2008 estimated sensitivity to moderate fluctuations in these key business parameters is shown in the accompanying table.

Funds Flow Sensitivity Summary

	Change in 2008 Funds Flow ($ million)	($/unit)
Change of $1.00 US/bbl in the price of WTI oil	0.61	0.03
Change in oil production of 100 bbl/d	1.96	0.10
Change of $0.10 US/mcf in the price of NYMEX natural gas	0.84	0.04
Change in natural gas production of one mmcf/d	1.79	0.09
Change in $0.01 in the $US/$Cdn exchange rate	1.63	0.08

BANK DEBT

On July 30, 2007, Zargon amended and renewed its syndicated committed credit facilities, which resulted in an increase in the available facilities and borrowing base to $120 million from the previous amount of $100 million. Subsequent to year end, Zargon again amended its syndicated committed credit facilities which further resulted in an increase in the available facilities and borrowing base to $150 million from the July 30, 2007 amount of $120 million. These facilities consist of a $130 million tranche available to the Canadian borrower and a US $18 million tranche available to the US borrower. This most recent increase in committed credit facilities was completed on January 31, 2008 and was performed in conjunction with Zargon's corporate acquisition of Rival Energy Ltd. These expanded facilities continue to be available for general corporate purposes and the potential acquisition of additional oil and gas properties. Pursuant to the January 2008 amendment, the $150 million demand debenture on the assets of the subsidiaries of the Trust, which have been provided as security for these facilities, was increased to $300 million. The facilities are fully revolving for a 364-day period with the provision for an annual extension at the option of the lenders and upon notice from Zargon's management. The next renewal date is July 29, 2008. Should the facilities not be renewed, they convert to one year non-revolving term facilities at the end of the revolving 364-day period. Repayment would not be required until the end of the non-revolving term and, as such, these facilities have been classified as long term debt. At December 31, 2007, bank debt was $56.87 million, an increase of $26.83 million from the prior year end bank debt amount of $30.04 million. The increase in bank debt was primarily attributed to net capital expenditures and cash distributions exceeding funds flow from operations during the year. Zargon reviews its compliance with its bank debt covenants on a quarterly basis and has no violations as at December 31, 2007.

Zargon's debt net of working capital (excluding unrealized risk management assets and liabilities) of $62.30 million at December 31, 2007 was equivalent to 78 percent of the 2007 funds flow from operations of $79.84 million. At December 31, 2006, the debt net of working capital (excluding unrealized risk management assets and liabilities) was $39.83 million, equivalent to 48 percent of the 2006 funds flow from operations of $82.89 million.

EQUITY

At March 12, 2008, Zargon had 17.676 million trust units and 2.060 million exchangeable shares outstanding. Assuming full conversion of exchangeable shares at the current effective exchange ratio of 1.31785, there would be 20.391 million trust units outstanding at this date. Pursuant to the trust unit rights incentive plan, there are currently an additional 1.476 million trust unit incentive rights issued and outstanding.

During 2007, 6.940 million Zargon trust units traded on The Toronto Stock Exchange with a high trading price of $31.24 per unit, a low of $21.35 per unit and a closing price of $23.06 per unit. The 2007 trading statistics show a 36 percent year-over-year decrease in trading volume and a seven percent decrease in the closing unit price. Zargon's market capitalization (including

the market value of exchangeable shares) at year end 2007 was approximately $456 million, compared to approximately $482 million at the end of 2006).

SEGMENTED GEOGRAPHIC INFORMATION

During 2007, approximately 86 percent (2006 – 84 percent) of Zargon's combined petroleum and natural gas revenue came from Western Canadian (Alberta, Saskatchewan and Manitoba) properties, with the remaining 14 percent (2006 – 16 percent) of revenues generated in the United States (North Dakota).

Off Balance Sheet Arrangements

The Trust has no guarantees or off balance sheet arrangements, except for letters of credit which have been issued in the normal course of business of approximately $0.44 million as at December 31, 2007.

Related Party Transactions

During the year, the Trust paid $0.05 million (2006 – $0.05 million) for vehicle leases to a company owned by a Board member; $0.07 million (2006 – $0.09 million) for legal services to a law firm in which a Board member is a partner; nil (2006 – $0.02 million) for field services to a company of which a senior Zargon officer is a Board member and nominal shareholder; and nil (2006 – $0.06 million) in consulting fees to a company owned by a Board member. All amounts were based on normal commercial terms and conditions.

Contractual Obligations

Zargon has certain contractual obligations relating to the lease of head office space and transportation contracts that extend for longer than one year as set out in the table below:

($ million)	Total	2008	2009 to 2010	2011 to 2012	Thereafter
Head office lease and other	5.64	1.27	2.46	1.91	–
Transportation contracts	1.03	0.75	0.26	0.02	–
Total	6.67	2.02	2.72	1.93	–

Critical Accounting Estimates

The preparation of the consolidated financial statements, in accordance with Canadian generally accepted accounting principles, requires management to make judgments and estimates that affect the financial results of the Trust. Zargon's management reviews its estimates regularly, but new information and changed circumstances may result in actual results or changes to estimated amounts that differ materially from current estimates. The critical estimates are discussed below:

PETROLEUM AND NATURAL GAS RESERVES

All of Zargon's petroleum and natural gas reserves are evaluated and reported on by independent petroleum engineering consultants in accordance with Canadian Securities Administrators' National Instrument 51-101 ("NI 51-101"). The estimation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production, commodity prices and the timing of future expenditures, all of which are subject to numerous uncertainties and various interpretations. The Trust expects that its estimates of reserves will change to reflect updated information. Reserve estimates can be revised upward or downward based on the results of future drilling, testing, production levels and changes in costs and commodity prices.

FULL COST ACCOUNTING

Zargon follows the full cost method of accounting for petroleum and natural gas operations as outlined in Canadian Institute of Chartered Accountants ("CICA") accounting guideline "Oil and Gas Accounting – Full Cost" (AcG-16). Under this accounting method, all costs related to the exploration for and development of petroleum and natural gas reserves are capitalized. Capitalized costs, as well as the estimated future expenditures to develop proved reserves, are depleted using the unit-of-production method based on estimated proved oil and natural gas reserves.

In applying the full cost method, Zargon calculates a ceiling test on a quarterly basis to ensure that the net carrying value of petroleum and natural gas assets do not exceed the estimated undiscounted future net cash flow from production of proved reserves. Accordingly, the Trust must base this calculation of future net cash flow on estimated forecasted sales prices, costs and regulations in effect at the period end. AcG-16 limits the carrying value of petroleum and natural gas properties to their fair value. The fair value is equal to estimated future cash flow from proved and probable reserves using future price forecasts and costs discounted at a risk-free rate.

ASSET RETIREMENT OBLIGATIONS

Zargon follows CICA Section 3110, "Asset Retirement Obligations", which requires liability recognition for retirement obligations associated with the Trust's property, plant and equipment. Under this policy, the Trust is required to provide for future removal and site restoration costs. The Trust must estimate these costs in accordance with existing laws, contracts or other policies and must also estimate a credit adjusted risk-free rate and inflation rate in this calculation. These estimated costs are charged to earnings and the appropriate liability account over the expected life of the asset. When the future removal and site restoration costs cannot be reasonably determined, a contingent liability may exist. Contingent liabilities are charged to earnings when management is able to determine the amount and the likelihood of the future obligation.

INCOME TAX ACCOUNTING

The determination of the Trust's income and other tax liabilities requires interpretation of complex laws and regulations. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded by management.

Recent Canadian Accounting Pronouncements

As of January 1, 2007, the Trust adopted CICA Section 1530 "Comprehensive Income", Section 3251 "Equity", Section 3855 "Financial Instruments – Recognition and Measurement", Section 3861 "Financial Instruments – Disclosure and Presentation" and Section 3865 "Hedges". Under the new standards, a new statement, the Consolidated Statement of Comprehensive Income, has been introduced that provides for certain gains and losses arising from changes in fair value, to be temporarily recorded outside the income statements. In addition, all financial instruments, including derivatives, are to be included in the Trust's consolidated balance sheets and measured, in most cases, at fair values and requirements for hedge accounting have been further clarified. There is no material impact to the Trust's consolidated financial statements as a result of implementing the new standards. As required by the new standards, prior periods have not been restated. Section 3251 establishes standards for the presentation of equity and changes in equity during the reporting period. This section specifies that changes in equity for the period arising from net earnings, other comprehensive income, other changes in earnings, changes in contributed surplus and changes in unitholders' capital must be presented separately.

As of January 1, 2007, the Trust adopted revised CICA Section 1506 "Accounting Changes", which provides expanded disclosures for changes in accounting policies, accounting estimates and correction of errors. Under the new standard, accounting changes should be applied retrospectively unless otherwise permitted or where impractical to determine. Also, voluntary changes in accounting policy are made only when required by a primary source of GAAP or when the change results in more relevant and reliable information. There is no material impact to the Trust's consolidated financial statements as a result of implementing this new standard.

The Trust has identified new and revised accounting pronouncements that have been issued that are not yet effective and determined that the following may have a significant impact on the Trust:

As of January 1, 2008, Zargon will be required to adopt two new CICA standards, Section 3862 "Financial Instruments – Disclosures" and Section 3863 "Financial Instruments – Presentation", which will replace Section 3861 "Financial Instruments – Disclosure and Presentation". The new disclosure standard increases the emphasis on the disclosure of the risks associated with both recognized and unrecognized financial instruments and how those risks are managed. The new presentation standard carries forward the former presentation requirements. The new financial instruments presentation and disclosure requirements were issued in December 2006 and the Trust is assessing the impact on its consolidated financial statements.

As of January 1, 2008, Zargon will be required to adopt the new CICA Section 1535 "Capital Disclosures", which will require companies to disclose their objectives, policies and processes for managing capital. In addition, disclosures are to include whether companies have complied with externally imposed capital requirements. The new capital disclosure requirements were issued in December 2006 and the Trust is assessing the impact on its consolidated financial statements.

The CICA Accounting Standards Board ("AcSB") has adopted a strategic plan for the direction of accounting standards in Canada. As part of that plan, accounting standards in Canada for public companies are to converge with International Financial Reporting Standards ("IFRS") by the end of 2011. The Trust continues to monitor and assess the impact of convergence of Canadian GAAP and IFRS.

In February 2008, the CICA issued Section 3064 "Goodwill and Intangible Assets", replacing Section 3062 "Goodwill and Other Intangible Assets". The new Section will be effective on January 1, 2009. Section 3064 establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets subsequent to its initial recognition. Standards concerning goodwill are unchanged from the standards included in the previous Section 3062. The Trust is currently evaluating the impact of the adoption of this new Section and does not expect a material impact on its consolidated financial statements.

Management and Financial Reporting Systems

DESIGN OF INTERNAL CONTROL OVER FINANCIAL REPORTING AND EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

The Trust has designed internal controls over financial reporting and has established procedures and internal control systems to ensure timely and accurate preparation of financial, internal management and other reports. Disclosure controls and procedures are in place to ensure all ongoing statutory reporting requirements are met and material information is disclosed on a timely basis. The President and Chief Executive Officer and the Executive Vice President and Chief Financial Officer, individually, sign certifications that the financial statements, together with the other financial information included in the regulatory filings, fairly present, in all

material respects, the financial conditions, results of operations and cash flows as of the dates and for the periods represented.

Our management, including our President and Chief Executive Officer and the Executive Vice President and Chief Financial Officer, have designed internal controls over financial reporting and have evaluated the effectiveness of the Trust's disclosure controls and procedures as at the end of the period covered by this report. Based on the above, the President and Chief Executive Officer and the Executive Vice President and Chief Financial Officer, have concluded that the Trust has designed internal controls over financial reporting and the Trust's disclosure controls are effective as at the end of the period covered by this annual report, in all material respects, after considering the Canadian Securities Administrator's Multilateral Instrument 52-109 "Certification of Disclosures in Issuers' Annual and Interim Filings."

Because of their inherent limitations, disclosure controls and procedures and internal controls over financial reporting may not prevent or detect misstatements, errors or fraud. Control systems, no matter how well conceived or operated, can provide only reasonable, not absolute assurance that the objectives of the control systems are met.

Business Risks and Outlook

BUSINESS RISKS

Zargon's external business risks arise from the uncertainty of oil and natural gas pricing, the uncertainty of interest and exchange rates, environmental and safety issues and financial and liquidity considerations. Additional risks arise from the production performance of existing properties (including natural decline), the changes in tax, royalty and other regulatory standards and uncertain results from capital expenditure programs.

Oil and natural gas prices may fluctuate widely in response to many factors such as global and North American supply and demand, economic conditions, weather conditions, political stability, the supply and price of imported oil and liquefied natural gas, production and storage levels of North American natural gas and government regulations. Zargon attempts to minimize pricing and currency exchange uncertainty with a risk management program that encompasses a variety of financial instruments. These could include forward sales of oil and natural gas production (either through financial derivative transactions such as swaps or by physical contracts), put options on both oil and natural gas, costless collars (in which some potential high price gain is given up in return for potential low price support) and US dollar currency risk management transactions in different forms for up to 35 percent of its oil and natural gas production volumes. In general, the Trust seeks to use strategies that allow minimum price expectations to be met in order that distributions and capital programs can be funded. This strategy is designed mainly to protect the Trust against periods of unusually low commodity prices and, by its nature, is likely to produce significant risk management losses when prices are unusually high.

Environmental and safety risks are mitigated through compliance with provincial and federal environmental and safety regulations by maintaining adequate insurance and by adopting appropriate emergency response and employee safety procedures.

The Trust is subject to a broad range of laws and regulatory requirements. Changes in government regulations, including reporting requirements, income tax laws, operating practices, environmental protection requirements and royalty rates can have a significant impact on Zargon. Although Zargon has no control over these regulatory risks, the Trust actively monitors changes, participates in industry organizations and, when required, engages the assistance of third party experts to assess the impact of such changes on the Trust's financial and operating results.

Financial and liquidity risks are reduced by limiting debt financing to self-imposed debt to funds flow guidelines. Zargon maintains a low cash distribution to funds flow from operations ratio to ensure funding is available for capital programs to sustain per unit production and reserves. Access to capital markets, if required for additional financing by either debt or equity issuances, is dependent upon maintaining strong performance and relationships with investors. A substantial portion of the Trust's accounts receivable are with companies in the oil and gas industry and are subject to normal industry credit risks. Management regularly monitors the aging of receivable balances to mitigate this risk. With respect to financial instruments utilized for risk management purposes, the Trust partially mitigates associated credit risk by limiting transactions to counterparties with investment grade credit ratings.

Changes to the Canadian income trust tax rules after 2010 and the Alberta government's October 25, 2007 royalty announcement may have negatively impacted the Canadian oil and gas trust industry's access to new capital from debt and equity markets in the future.

Recent global credit issues arising from deteriorating credit markets (regarding asset-backed commercial paper) may also have negatively impacted overall access to new capital from debt and equity markets in the near future. Zargon has not been directly impacted by these issues as the Trust did not hold any credit positions in such investments. The recent amendments to its credit facilities provide Zargon reasonable capacity for its operations in the near future.

Zargon actively manages the risks of its capital programs and reserves by concentrating drilling and subsequent development activities in areas where it has demonstrated proven technical capabilities and understanding. Zargon's capital budget is managed to limit exposure so that significant capital is not risked on any one project or concept.

ENVIRONMENTAL REGULATION AND RISK

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. In 2002, the Government of Canada ratified the Kyoto Protocol (the "Protocol"), which calls for Canada to reduce its greenhouse gas emissions to specified levels. There has been much public debate with respect to Canada's ability to meet these targets and the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases.

Recently the Federal Government released its Action Plan to Reduce Greenhouse Gases and Air Pollution (the "Action Plan"), also known as "ecoACTION", which includes the Regulatory Framework for Air Emissions, and the Alberta Government has also introduced legislation regarding greenhouse gas emissions.

On March 8, 2007, the Alberta government introduced legislation to reduce greenhouse gas emission intensity. Bill 3 states that facilities emitting more than 100,000 tonnes of greenhouse gases per year must reduce their emissions intensity by 12 per cent over the average emissions levels of 2003, 2004 and 2005; if they are not able to do so, these facilities will be required to pay $15 per tonne for every tonne above the 12 per cent target, beginning on July 1, 2007. At this time, the Trust has determined that there is currently no impact of this legislation on Zargon's existing facilities ownership.

Although Zargon is not a large emitter of greenhouse gases, the Trust continues to monitor developments in this area. Although environmental legislation is evolving in a manner that could result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs, it is not possible to predict the impact of these requirements on the Trust and its operations and financial condition at this time.

ALBERTA ROYALTY AND TAX REGIME

On February 16, 2007, the Alberta Government announced that a review of the Province's royalty and tax regime (including income tax and freehold mineral rights tax) pertaining to oil and gas resources, including oil sands, conventional oil and gas and coalbed methane, would be conducted by a panel of experts with the assistance of individual Albertans and key stakeholders. On September 18, 2007, the Royalty Review Panel delivered its final report and recommendations to the Government of Alberta. The report titled "Our Fair Share" recommended significant increases to royalties levied on natural gas, conventional oil and oil sands produced in Alberta. On October 25, 2007, the Alberta Government released details of its planned implementation of the final Royalty Review Panel report, titled "The New Royalty Framework" ("NRF"). Zargon has reviewed the modifications proposed by the Government of Alberta to its royalty program, which is scheduled to take effect on January 1, 2009. While more detailed analysis is ongoing, the following observations have been noted:

- Currently, 35 percent of Zargon's production is from properties located outside Alberta and is therefore not affected by the NRF.
- Royalties determined under the NRF will be determined based on commodity prices, well productivity and depth of wells. A significant portion of Zargon's wells are lower productivity wells that, on a relative basis, are less impacted by the NRF than higher productivity wells.
- Zargon has recalculated its January 1, 2008 reserves using Zargon's independent engineering firm McDaniel & Associates Consultants Ltd. using the January 1, 2008 escalated price forecast (present value before tax at 10 percent) under both the existing and NRF proposed royalty rates. The impact of the proposed change in royalty rates on the net present value of Zargon's proved and probable reserves was relatively neutral.
- The NRF will have a more significant impact on the economics of Zargon's ongoing natural gas exploration programs, which target moderate rate natural gas wells in our West Central Alberta and Alberta Plains core areas. Consequently, commencing in 2009, the project economics for Zargon's natural gas exploration programs will be directly and negatively impacted as most natural gas prices by the increased royalties outlined in the Alberta Government's NRF report.

OUTLOOK

With a strong balance sheet, 362 thousand net acres of undeveloped land and a promising project inventory that has recently been augmented by the January 2008 closing of the Rival acquisition, Zargon continues to be well positioned to meet its value-creating objectives in 2008. At this time in early March 2008, future commodity markets indicate that in 2008 both oil and natural gas prices will exceed their 2007 averages. Furthermore, there is evidence that some of the upward pressures on the industry's input costs have been alleviated, allowing for improved capital program efficiencies for field activities and for property and corporate acquisitions.

Although changes to the Canadian income trust tax rules after 2010 and the Alberta government's October 25, 2007 royalty announcement have negatively impacted our industry, we are optimistic about Zargon's long term value-seeking strategy in this evolving business. Consistent with its history, Zargon will continue to adhere to a focused strategy of exploring and exploiting its existing asset base while executing accretive acquisitions which will be funded by debt or equity issuances.

Selected Quarterly Information

($ million, except per unit amounts)	2007				2006			
	Q4	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1
Petroleum and natural gas revenue	**41.13**	**36.64**	**39.21**	**38.53**	36.50	37.93	38.66	40.94
Funds flow from operations[1]	**20.10**	**17.38**	**20.56**	**21.80**	18.84	19.87	22.06	22.12
Per unit – diluted	**1.02**	**0.88**	**1.05**	**1.12**	0.97	1.02	1.14	1.15
Net earnings	**2.20**	**5.50**	**11.63**	**5.22**	7.05	12.31	13.22	11.92
Per unit – diluted	**0.13**	**0.32**	**0.68**	**0.31**	0.43	0.73	0.79	0.72
Cash distributions	**9.21**	**9.19**	**9.17**	**9.12**	9.05	9.00	8.96	8.89
Per trust unit	**0.54**	**0.54**	**0.54**	**0.54**	0.54	0.54	0.54	0.54
Net capital expenditures	**18.35**	**16.43**	**10.97**	**20.93**	20.41	18.99	8.78	15.19
Total assets	**340.19**	**327.54**	**324.96**	**324.31**	310.57	294.14	283.86	282.35
Bank debt	**56.87**	**44.10**	**46.74**	**37.68**	30.04	20.71	18.14	26.64

1. *Throughout this report, funds flow from operations is now calculated inclusive of asset retirement expenditures. All prior period calculations have been restated to reflect this change.*

Fourth Quarter 2007 Results

During the fourth quarter of 2007, Zargon's petroleum and natural gas revenues of $41.13 million were 12 percent higher than the previous quarter's revenues. Production for the 2007 fourth quarter of 8,790 barrels of oil equivalent per day exceeded the fourth quarter guidance of 8,625 barrels of oil equivalent per day by two percent and was three percent higher than the 2007 third quarter's production of 8,501 barrels of oil equivalent per day. Compared to the previous quarter, oil production increased two percent to 3,666 barrels per day as Williston Basin and Alberta Plains (Taber area) wells were placed on production. Fourth quarter natural gas production increased four percent over the previous quarter to 30.74 million cubic feet per day as recently drilled West Central Alberta and Alberta Plains natural gas wells were tied-in. Average field prices received during the fourth quarter, before the impact of financial risk management contracts, were $71.29 per barrel for oil and liquids and $5.95 per thousand cubic feet for natural gas, a five percent increase and a 14 percent increase, respectively, compared to the 2007 third quarter prices. Reflecting market and seasonal trends, Zargon's field price differential for its blended 30 degree API crude oil stream increased to a $15.13 per barrel discount to the Edmonton reference crude oil price, a 44 percent increase from Zargon's average differential of $10.50 per barrel for the first nine months of 2007.

Funds flow from operations was $20.10 million in the fourth quarter, an increase of 16 percent or $2.72 million over the prior quarter. A comparative analysis of the primary factors that caused this quarter-over-quarter increase is as follows:

- Fourth quarter 2007 petroleum and natural gas revenues of $41.13 million were $4.49 million or 12 percent higher than the 2007 third quarter revenues of $36.64 million. This revenue increase was a result of the three percent increase in production volumes and the nine percent increase in average realized commodity prices.
- Realized risk management losses were $0.30 million in the fourth quarter of 2007, a $1.41 million change over the prior quarter's $1.11 million of risk management gains. The primary reason for the fourth quarter net loss related to gains ($1.39 million) being realized on financial natural gas risk management contracts being more than offset by losses ($1.69 million)

realized on financial oil risk management contracts. Natural gas prices continued to be weak during the 2007 fourth quarter, while oil prices continued to be relatively strong.

- Royalties for the fourth quarter were $8.26 million, an increase of $0.63 million from the prior quarter. The average royalty rate for the quarter of 20.1 percent was similar to the 20.8 percent from the 2007 third quarter. This small decline in the average royalty rate is attributed to the effect of fourth quarter gains recognized on fixed price physical natural gas contracts, which increase natural gas pricing and revenue but are not subject to royalties.

- Production expenses were $8.50 million for the quarter, a $0.06 million or one percent decrease from the third quarter of 2007. On a per barrel of oil equivalent basis, production expenses decreased four percent to $10.51 in the fourth quarter of 2007 compared to $10.95 in the prior quarter. This quarterly decline in per unit costs was due in part to reduced levels of Williston Basin workovers, seasonal repairs and maintenance costs.

- General and administrative expenses increased in the fourth quarter by $0.51 million over the third quarter of 2007. This is a 24 percent increase compared to the prior quarter and is primarily due to amounts recorded for year end performance-based compensation for employees.

- Interest and financing charges in the fourth quarter were $0.92 million, an increase of nine percent or $0.08 million from the prior quarter. The average debt level for the fourth quarter increased 18 percent to $61.04 million compared to $51.88 million in the third quarter of 2007, resulting in increased debt servicing charges.

- Current income taxes of $0.14 million were $0.69 million lower than the 2007 third quarter taxes. The decrease was primarily due to a reduction in estimated United States taxable income related to an active fourth quarter capital expenditure program in this geographic region.

- Asset retirement expenditures reflect the actual amounts incurred to abandon and reclaim unutilized non-producing wells. These asset retirement expenditures totalled $0.29 million in the 2007 fourth quarter and were reduced from the prior quarter amount of $0.38 million. The difference between accretion expenses (as reflected on the income statements) and asset retirement expenditures are a result of the timing differences between the estimating of future expenses and the actual incurrence of actual expenses during the period.

Net earnings for the quarter decreased $3.30 million to $2.20 million, a 60 percent decrease compared to the third quarter 2007 net earnings of $5.50 million. Net earnings track the funds flow from operations for the respective periods modified by asset retirement expenditures and non-cash charges, which included the following for the fourth quarter of 2007:

- Unit-based compensation expense increased by $0.15 million during the fourth quarter of 2007 to $0.56 million, a 35 percent increase over the third quarter. The increase is a result of additional unit rights granted in the fourth quarter of 2007.

- Depletion and depreciation expense increased by $0.74 million to $12.92 million in the fourth quarter. The additional expense resulted from the increased production in the fourth quarter and the use of an updated depletion and depreciation rate of $15.98 per barrel of oil equivalent, compared to the prior quarter's $15.58 per barrel of oil equivalent charge. The increased per unit charges are calculated on the basis of the recently completed 2007 year end reserve appraisal prepared by independent engineers that reflects Zargon's, and the industry's, trend to higher finding and development costs. Furthermore, 2007 depletion and depreciation rates continue to increase quarterly as a result of ongoing increases in the property and equipment balance from the conversion of exchangeable shares due to the application of EIC-151.

- Unrealized risk management losses in the 2007 fourth quarter of $9.82 million were 316 percent or $7.46 million higher than the third quarter loss of $2.36 million. These unrealized losses result from "marking-to-market" financial risk management contracts at each period end. During the fourth quarter, unrealized risk management losses resulted from stronger commodity pricing at the December 31, 2007 mark-to-market date when compared to the third quarter September 30, 2007 mark-to-market date. In particular, higher year end futures oil pricing resulted in unrealized contract losses of $8.50 million. Additionally, the natural gas losses of $1.32 million were also the result of higher year end futures natural gas pricing. The realization and the expiry of certain financial natural gas and oil contracts also affect the mark-to-market amounts.

- The provision for accretion of asset retirement obligations for the 2007 fourth quarter was $0.42 million, an increase of $0.09 million or 28 percent when compared to the prior quarter expense. The quarter-over-quarter increase is due to changes in the estimated future liability for asset retirement obligations as a result of wells added through Zargon's drilling program inclusive of wells acquired/disposed of in the quarter and changes resulting from revisions to the timing and the amounts of the original estimates of undiscounted cash flows.

- The future income tax recovery was $6.35 million during the quarter compared to a future income tax recovery of $3.77 million from the third quarter of 2007. The future income tax recovery in the 2007 fourth quarter was due to a substantive enactment of reduced future federal income tax rates and the significant decrease of earnings to a loss position before taxes of $3.66 million compared to the third quarter earnings before taxes of $3.41 million. In summary, the fourth quarter decrease in net earnings was primarily derived by the increase of non-cash unrealized risk management contract losses in the quarter.

- Reduction in earnings due to non-controlling interests pertaining to exchangeable shares decreased to $0.35 million in the 2007 fourth quarter from $0.86 million in the third quarter. This was due to a decrease in net earnings before non-controlling interest in the fourth quarter.

Net capital expenditures were $18.35 million during the fourth quarter of 2007, a 12 percent increase from the prior quarter amount of $16.43 million. During the fourth quarter, Zargon completed an extensive field capital program focused on Alberta Plains core area Taber horizontal oil wells, West Central Alberta natural gas exploration locations and Williston Basin core area horizontal oil exploitation wells. During the fourth quarter of 2007, 9.0 net wells were drilled compared to 20.9 net wells in the third quarter of 2007.

Cash distributions to unitholders declared for the quarter totalled $9.21 million

Additional Information

Additional information regarding the Trust and its business operations, including the Trust's Annual Information Form for December 31, 2007, is available on the Trust's SEDAR profile at www.sedar.com.

Management's Report

The consolidated financial statements of Zargon Energy Trust were prepared by management in accordance with Canadian generally accepted accounting principles. The financial and operating information presented in this annual report is consistent with that shown in the consolidated financial statements.

Management has designed and maintains a system of internal accounting controls that provide reasonable assurance that all transactions are accurately recorded, that the financial statements reliably report the Trust's operations and that the Trust's assets are safeguarded. Timely release of financial information sometimes necessitates the use of estimates when transactions affecting the current accounting period cannot be finalized until future periods. Such estimates are based on careful judgments made by management.

Ernst & Young LLP, an independent chartered accountant firm, was appointed by a resolution of the unitholders to audit the consolidated financial statements of the Trust and provide an independent opinion. They have conducted an independent examination of the Trust's accounting records in order to express their opinion on the consolidated financial statements.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board of Directors exercises this responsibility through its Audit Committee. The Audit Committee, which consists of non-management directors, has met with Ernst & Young LLP and management in order to determine that management has fulfilled its responsibilities in the preparation of the consolidated financial statements. The Audit Committee has reported its findings to the Board of Directors, who have approved the consolidated financial statements.

C.H. Hansen
President and Chief Executive Officer

B.C. Heagy
Executive Vice President and
Chief Financial Officer

Calgary, Canada
March 12, 2008

Auditors' Report

To the Unitholders of **Zargon Energy Trust**

We have audited the consolidated balance sheets of Zargon Energy Trust as at December 31, 2007 and 2006 and the consolidated statements of earnings and comprehensive income and accumulated earnings and cash flows for the years then ended. These financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2007 and 2006 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Calgary, Canada
March 12, 2008

Ernst & Young LLP
Chartered Accountants

Consolidated Balance Sheets

As at December 31 ($ thousands)	2007	2006
ASSETS [notes 5 and 19]		
Current		
Accounts receivable [note 11]	**21,668**	18,362
Prepaid expenses and deposits	**3,145**	3,281
Unrealized risk management asset [note 11]	**1,432**	5,817
	26,245	27,460
Property and equipment, net [note 4]	**313,949**	283,108
	340,194	310,568
LIABILITIES		
Current		
Accounts payable and accrued liabilities	**27,172**	28,410
Cash distributions payable [note 17]	**3,074**	3,022
Unrealized risk management liability [note 11]	**12,430**	20
	42,676	31,452
Long term debt [note 5]	**56,868**	30,037
Asset retirement obligations [note 6]	**21,184**	17,307
Future income taxes [note 9]	**37,258**	47,891
	157,986	126,687
Commitments and contingencies [notes 5, 7, 11, 12 and 13]		
NON-CONTROLLING INTEREST		
Exchangeable shares [note 8]	**20,730**	18,319
UNITHOLDERS' EQUITY		
Unitholders' capital [note 7]	**89,688**	82,868
Contributed surplus [note 7]	**3,714**	2,475
Accumulated earnings	**188,819**	164,267
Accumulated cash distributions [note 17]	**(120,743)**	(84,048)
	161,478	165,562
	340,194	310,568

See accompanying notes to the consolidated financial statements.

On behalf of the Board:

K.J. Harrison
Director

K.D. Kitagawa
Director

Consolidated Statements of Earnings and Comprehensive Income and Accumulated Earnings

For the years ended December 31 ($ thousands, except per unit amounts)	2007	2006
REVENUE		
Petroleum and natural gas revenue	**155,512**	154,039
Unrealized risk management gain/(loss) [note 11]	**(16,796)**	9,553
Realized risk management gain/(loss)	**4,255**	(569)
Royalties	**(32,746)**	(33,431)
	110,225	129,592
EXPENSES		
Production	**32,620**	26,416
General and administrative	**8,209**	6,973
Unit-based compensation [note 7]	**1,705**	1,856
Interest and financing charges [note 5]	**3,071**	1,532
Unrealized foreign exchange (gain)/loss	**(226)**	24
Accretion of asset retirement obligations [note 6]	**1,406**	1,244
Depletion and depreciation	**48,410**	41,136
	95,195	79,181
EARNINGS BEFORE INCOME TAXES	**15,030**	50,411
INCOME TAXES [note 9]		
Current	**2,143**	1,598
Future (recovery)	**(15,470)**	(2,824)
	(13,327)	(1,226)
EARNINGS BEFORE NON-CONTROLLING INTEREST	**28,357**	51,637
Non-controlling interest – exchangeable shares [note 8]	**(3,805)**	(7,138)
NET EARNINGS AND COMPREHENSIVE INCOME	**24,552**	44,499
ACCUMULATED EARNINGS, BEGINNING OF YEAR	**164,267**	119,768
ACCUMULATED EARNINGS, END OF YEAR	**188,819**	164,267
NET EARNINGS PER UNIT [note 10]		
Basic	**1.45**	2.68
Diluted	**1.45**	2.68

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Cash Flows

For the years ended December 31 ($ thousands)	2007	2006
OPERATING ACTIVITIES		
Net earnings for the year	**24,552**	44,499
Add (deduct) non-cash items:		
Non-controlling interest – exchangeable shares	**3,805**	7,138
Unrealized risk management (gain)/loss	**16,796**	(9,553)
Depletion and depreciation	**48,410**	41,136
Accretion of asset retirement obligations	**1,406**	1,244
Unit-based compensation	**1,705**	1,856
Unrealized foreign exchange (gain)/loss	**(226)**	24
Future income taxes (recovery)	**(15,470)**	(2,824)
Asset retirement expenditures	**(1,140)**	(627)
	79,838	82,893
Changes in non-cash working capital [note 14]	**(3,535)**	842
	76,303	83,735
FINANCING ACTIVITIES		
Advances of bank debt	**26,831**	19,698
Cash distributions to unitholders	**(36,695)**	(35,902)
Exercise of unit rights	**2,127**	4,018
Changes in non-cash financing working capital [note 14]	**52**	(8,099)
	(7,685)	(20,285)
INVESTING ACTIVITIES		
Additions to property and equipment	**(67,850)**	(67,909)
Proceeds on disposal of property and equipment	**1,181**	4,543
Changes in non-cash investing working capital [note 14]	**(1,949)**	(84)
	(68,618)	(63,450)
NET CHANGE IN CASH DURING THE YEAR AND CASH, END OF YEAR	**–**	–

See supplemental cash flow information contained in note 15.

See accompanying notes to the consolidated financial statements.

Notes to the Consolidated Financial Statements

December 31, 2007 and 2006
All amounts are stated in Canadian dollars unless otherwise noted.

1. STRUCTURE OF THE TRUST

On July 15, 2004, Zargon Oil & Gas Ltd. (the "Company") was reorganized into Zargon Energy Trust (the "Trust" or "Zargon") as part of a Plan of Arrangement (the "Arrangement"). Shareholders of the Company received one trust unit or one exchangeable share for each common share held. The unitholders of the Trust are entitled to receive cash distributions paid by the Trust. Holders of exchangeable shares are not eligible to receive cash distributions paid, but rather, on each payment of a distribution, the number of trust units into which each exchangeable share is exchangeable is increased on a cumulative basis in respect of the distribution. The Trust is an unincorporated open-end investment trust established under the laws of the Province of Alberta and was created pursuant to a trust indenture ("Trust Indenture").

The Trust's principal business activity is the exploration for and development and production of petroleum and natural gas in Canada and the United States ("US").

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation and Consolidation

These consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles ("GAAP"). Because a precise determination of many assets and liabilities is dependent upon future events, the preparation of periodic financial statements necessarily involves the use of estimates and approximations. Accordingly, actual results could differ materially from those estimates. The consolidated financial statements have, in management's opinion, been properly prepared within reasonable limits of materiality and within the framework of the Trust's accounting policies summarized below.

The consolidated financial statements include the accounts of Zargon Energy Trust, all of its subsidiaries and a partnership. All subsidiaries and the partnership are directly or indirectly owned and their operations are fully reflected in the consolidated financial statements.

Revenue Recognition

Petroleum and natural gas revenue is recognized in earnings when reserves are produced and delivered to the purchaser.

Joint Operations

The majority of the petroleum and natural gas operations of the Trust are conducted jointly with others, and accordingly, these consolidated financial statements reflect only the proportionate interests of the Trust in such activities.

Property and Equipment

The Trust follows the full cost method of accounting for its oil and natural gas operations whereby all costs relating to the acquisition, exploration and development of oil and natural gas reserves are capitalized and accumulated in separate cost centres for Canada and the United States. Such costs include land acquisition costs, annual carrying charges of non-producing properties, geological and geophysical costs and costs of drilling and equipping wells.

Depletion and depreciation of petroleum, natural gas properties and equipment is computed using the unit of production method based on the estimated proved reserves of petroleum and natural gas before royalties determined by independent consultants. For purposes of this calculation, reserves are converted to common units on the basis that six thousand cubic feet of natural gas is equivalent to one barrel of oil. A portion of the cost of petroleum and natural gas rights relating to undeveloped properties is excluded from the depletion calculation. Twenty percent of the year end balance of these costs is added to the depletion base each year. Proceeds on the disposal of petroleum and natural gas properties are applied against capitalized costs, with gains or losses not ordinarily recognized, unless such a disposal would result in a change in the depletion rate of 20 percent or more.

Depreciation of office equipment is provided using the declining balance method at an annual rate of 20 percent. Leasehold improvements are depreciated over the term of the lease.

Impairment Test

The Trust applies an impairment test to petroleum, natural gas properties and equipment costs on a quarterly basis or more frequently as events or circumstances dictate. This impairment test is performed on both the Canadian and US cost centres. An impairment loss exists when the carrying amount of the Trust's petroleum, natural gas properties and equipment exceeds the estimated undiscounted future net cash flows associated with the Trust's proved reserves (before royalties). If an impairment loss is determined to exist, the costs carried on the consolidated balance sheets in excess of the fair value of the Trust's proved and probable reserves are charged to earnings. Reserves are determined pursuant to evaluation by independent engineers as dictated by National Instrument 51-101.

Asset Retirement Obligations

Zargon recognizes the fair value of an Asset Retirement Obligation ("ARO") in the period in which it is incurred when a reasonable estimate of the fair value can be made. The fair value of the estimated ARO is recorded as a liability, with a corresponding increase in the carrying amount of the related asset. The capitalized amount is depleted on the unit of production method based on proved reserves (before royalties). The liability amount is increased each reporting period due to the passage of time and the amount of accretion is expensed in the period. Actual costs incurred upon the settlement of the ARO are charged against the liability.

Financial Instruments

Derivative financial instruments are utilized to reduce commodity price risk associated with the Trust's production of oil and natural gas. The base prices for the commodities are sometimes denominated in US dollars and the Trust may also use such financial instruments to reduce the related foreign currency risk. Financial instruments may also be used from time to time to reduce interest rate risk on outstanding debt. The Trust does not enter into financial instruments for trading or speculative purposes.

The Trust follows a policy of using risk management instruments such as fixed price swaps, forward sales, puts and costless collars. The objective is to partially offset or mitigate the wide price swings commonly encountered in oil and natural gas commodities and in so doing protect a minimum level of cash flow in periods of low commodity prices.

For financial risk management contracts entered into prior to December 31, 2004, the Trust's policy was to designate each derivative financial instrument employed as a hedge of a specific portion of projected production over the term of the instrument. The Trust formally documented its risk management objectives and strategies for undertaking the hedged transactions, the hedging item, the nature of the specific risk exposures being hedged, the intended term of the hedge relationship, the method for assessing effectiveness and the method of accounting for the hedging relationship. The effectiveness of the derivative was assessed on an ongoing basis to ensure that the derivatives entered into were highly effective in offsetting changes in fair values of the hedged items. The instruments employed could have been denominated in US or Canadian dollars. Gains or losses from all hedging contracts, other than forward sales settled by physical delivery, were recognized as hedging gains or losses when the sale of hedged production occurred. The Trust believed these derivative financial instruments used were effective as hedges over their term. In the event that a designated hedged item ceased to exist, any realized or unrealized gain or loss on such derivative commodity instruments were to be recognized in earnings immediately. If the hedge relationship was terminated, either via ineffectiveness or via termination of the designation, gains or losses previously deferred continued to be deferred and recognized when they were realized. As at June 30, 2006, all designated hedge contracts had expired.

For financial risk management contracts entered into after December 31, 2004, the Trust does consider these contracts to be effective on an economic basis but has decided not to designate these contracts as hedges for accounting purposes and, accordingly, for outstanding contracts not designated as hedges, an unrealized gain or loss is recorded based on the change in fair value (mark-to-market) of the contracts at each reporting period end. These instruments have been recorded as unrealized risk management assets/liabilities in the consolidated balance sheets.

In the case of forward sales, the instrument can sometimes be satisfied by physical delivery. In the case of physical delivery, the payment/receipt is recorded as part of the normal revenue stream.

Foreign currency swap agreements may be used from time to time to manage the risk inherent in producing commodities whose price is based directly or indirectly on US dollars, using a notional principal amount equal to the projected monthly revenue from their sale. Payments or charges are calculated and paid according to the terms of the agreement, usually with monthly settlement. At December 31, 2007 and 2006, the Trust had no such financial instruments.

The Trust had no interest rate financial instruments at December 31, 2007 and 2006.

Income Taxes

The Trust follows the liability method of tax allocation in accounting for income taxes. Under this method, the Trust records future income taxes for the effect of any differences between the accounting and income tax basis of an asset or liability using income tax rates expected to apply in the periods in which these temporary differences are expected to be recovered or settled. The effect on future income tax assets and liabilities of a change in tax rates is recognized in earnings in the period in which the change is substantively enacted.

Foreign Currency Translation

The Trust uses the temporal method of foreign currency translation whereby the monetary assets and liabilities recorded in a foreign currency are translated into Canadian dollars at year end exchange rates, and non-monetary assets and liabilities at the exchange rates prevailing when the assets were acquired or liability incurred. Revenues and expenses are translated at the average rate of exchange prevailing during the year. Gains and losses on translation are included in the consolidated statements of earnings and comprehensive income.

Trust Unit Rights and Unit-Based Compensation

Under the Trust's unit rights incentive plan (the "Plan"), rights to purchase trust units are allowed to be granted to directors, officers, employees and other service providers at current market prices. The Plan allows for the exercise price of rights to be reduced in future periods by an amount that distributions exceed a stated return on assets. Under the fair value method of accounting for unit-based compensation the cost of the option is charged to earnings with an offsetting amount recorded in contributed surplus, based on an estimate from the fair value model. Forfeiture of rights are recorded as a reduction in expense in the period in which they occur.

Per Unit Amounts

Per unit amounts are calculated using the weighted average number of trust units outstanding during the year. Diluted per unit amounts are calculated using the treasury stock method to determine the dilutive effect of unit-based compensation. The Trust follows the treasury stock method, which assumes that the proceeds received from "in-the-money" trust unit rights and unrecognized future unit-based compensation expense are used to repurchase units at the average market rate during the year. Diluted per unit amounts also include exchangeable shares using the "if-converted" method, whereby it is assumed the conversion of the exchangeable shares occurs at the beginning of the reporting period (or at the time of issuance if later).

Measurement Uncertainty

The amounts recorded for depletion and depreciation of property and equipment and the assessment of these assets for impairment are based on estimates of proved reserves, production rates, petroleum and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the impact on the consolidated financial statements of changes in such estimates in future periods could be material.

Inherent in the fair value calculation of asset retirement obligations are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal and regulatory environments. To the extent future revisions to these assumptions impact the fair value of the existing asset retirement obligation liability, a corresponding adjustment is made to the property and equipment balance.

Cash Distributions

The Trust declares monthly distributions of cash to unitholders of record on the last day of each calendar month. Pursuant to the Trust's policy, it will pay distributions to its unitholders subject to satisfying its financing covenants. Such distributions are recorded as distributions of equity upon declaration of the distribution.

3. CHANGES IN ACCOUNTING POLICIES

On January 1, 2007, the Trust adopted the Canadian Institute of Chartered Accountants ("CICA") Handbook Section 1530 "Comprehensive Income", Section 3251 "Equity", Section 3855 "Financial Instruments – Recognition and Measurement", Section 3861 "Financial Instruments – Disclosure and Presentation" and Section 3865 "Hedges". As required by the new standards, prior periods have not been restated.

The adoption of these standards has had no material impact on the Trust's net earnings or cash flows. The other effects of the implementation of the new standards are discussed below.

Comprehensive Income

The new standards introduce comprehensive income, which consists of net earnings and other comprehensive income ("OCI"). Upon adoption of Section 1530, the Trust revised its "Consolidated Statements of Earnings and Accumulated Earnings" to include the newly required statement of comprehensive income by creating a combined statement.

CICA Section 1530 introduces a new requirement to temporarily present certain gains and losses from changes in fair value outside net earnings. It includes unrealized gains and losses such as: changes in the currency translation adjustment relating to self-sustaining foreign operations; unrealized gains or losses on available-for-sale investments; and the effective portion of gains or losses on derivatives designated as cash flow hedges.

The adoption of comprehensive income has been made in accordance with the applicable transitional provisions and no amounts have been reclassified to accumulated other comprehensive income. Currently, Zargon has no OCI.

Equity

Section 3251 establishes standards for the presentation of equity and changes in equity during the reporting period. This section specifies that changes in equity for the period arising from net earnings, OCI, other changes in earnings, changes in contributed surplus, and changes in unitholders' capital must be presented separately.

Financial Instruments

The financial instruments standard establishes the recognition and measurement criteria for financial assets, financial liabilities and derivatives. All financial instruments are required to be measured at fair value on initial recognition of the instrument, except for certain related party transactions. Measurement in subsequent periods depends on whether the financial instrument has been classified as "held-for-trading", "available-for-sale", "held-to-maturity", "loans and receivables", or "other financial liabilities" as defined by the standard.

Financial assets and financial liabilities classified as "held-for-trading" are measured at fair value with changes in fair value recognized in earnings. Financial assets classified as "available-for-sale" are measured at fair value, with changes in fair value recognized in OCI until the asset is removed from the consolidated balance sheets. Financial assets classified as "held-to-maturity", "loans and receivables" and "other financial liabilities" are measured at amortized cost using the effective interest method of amortization. The methods used by the Trust in determining fair value of financial instruments are unchanged as a result of implementing the new standard.

Accounts receivable are designated as "loans and receivables". Accounts payable and accrued liabilities, cash distributions payable and long term debt are designated as "other liabilities".

The adoption of the financial instruments standard has been made in accordance with its transitional provisions. Accordingly, at January 1, 2007, $0.17 million of prepaid expenses and deposits were expensed to reflect the adopted policy of expensing long term debt transaction costs, premiums and discounts related to long term debt. Previously, the Trust deferred these costs within prepaid expenses and deposits and amortized them on a straight-line basis over the term of the related long term debt. The adoption of the expensing method had no impact on opening accumulated earnings.

Risk management assets and liabilities are derivative financial instruments classified as "held-for-trading". Additional information on the Trust's accounting treatment of derivative financial instruments is contained in note 2.

CICA Section 3865 provides alternative treatments to Section 3855 for entities that choose to designate qualifying transactions as hedges for accounting purposes. It replaces and expands on Accounting Guideline 13 "Hedging Relationships" and the hedging guidance in Section 1650 "Foreign Currency Translation" by specifying how hedge accounting is applied and what disclosures are necessary when it is applied. As Zargon currently uses mark-to-market accounting for its derivative financial instruments there is no material impact to the Trust's consolidated financial statements as a result of implementing this new standard.

As of January 1, 2007, the Trust adopted revised CICA Section 1506 "Accounting Changes", which provides expanded disclosures for changes in accounting policies, accounting estimates and corrections of errors. Under the new standard, accounting changes should be applied retrospectively unless otherwise permitted or where impractical to determine. As well, voluntary changes in accounting policy are made only when required by a primary source of GAAP or when the change results in more relevant and reliable information. There is no material impact to the Trust's consolidated financial statements as a result of implementing this new standard.

Future Accounting Pronouncements

The Trust has identified new and revised accounting pronouncements that have been issued that are not yet effective and determined that the following may have a significant impact to the Trust:

As of January 1, 2008, Zargon will be required to adopt two new CICA standards, Section 3862 "Financial Instruments – Disclosures" and Section 3863 "Financial Instruments – Presentation", which will replace Section 3861 "Financial Instruments – Disclosure and Presentation". The new disclosure standard increases the emphasis on the disclosure of the risks associated with both recognized and unrecognized financial instruments and how those risks are managed. The new presentation standard carries forward the former presentation requirements. The new financial instruments presentation and disclosure requirements were issued in December 2006 and the Trust is assessing the impact on its consolidated financial statements.

As of January 1, 2008, Zargon will be required to adopt the new CICA Section 1535 "Capital Disclosures", which will require companies to disclose their objectives, policies and processes for managing capital. In addition, disclosures are to include whether companies have complied with externally imposed capital requirements. The new capital disclosure requirements were issued in December 2006 and the Trust is assessing the impact on its consolidated financial statements.

In February 2008, the CICA issued Section 3064 "Goodwill and Intangible Assets", replacing Section 3062 "Goodwill and Other Intangible Assets". The new Section will be effective on January 1, 2009. Section 3064 establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets subsequent to its initial recognition. Standards concerning goodwill are unchanged from the standards included in the previous Section 3062. The Trust is currently evaluating the impact of the adoption of this new Section, however does not expect a material impact on its consolidated financial statements.

The CICA Accounting Standards Board ("AcSB") has adopted a strategic plan for the direction of accounting standards in Canada. As part of that plan, accounting standards in Canada for public companies are to converge with International Financial Reporting Standards ("IFRS") by the end of 2011. The Trust continues to monitor and assess the impact of convergence of Canadian GAAP and IFRS.

4. PROPERTY AND EQUIPMENT

	December 31, 2007		
($ thousands)	Cost	Accumulated Depletion and Depreciation	Net Book Value
Petroleum, natural gas properties and equipment*	**535,850**	**223,780**	**312,070**
Leasehold improvements and office equipment	**3,107**	**1,228**	**1,879**
	538,957	**225,008**	**313,949**

	December 31, 2006		
($ thousands)	Cost	Accumulated Depletion and Depreciation	Net Book Value
Petroleum, natural gas properties and equipment*	457,865	175,585	282,280
Leasehold improvements and office equipment	1,841	1,013	828
	459,706	176,598	283,108

** As a result of shareholders redeeming exchangeable shares, property and equipment has cumulatively increased $51.76 million; $8.82 million relating to 2007, $6.73 million relating to 2006, $24.93 million relating to 2005 and $11.28 million relating to 2004. The effect of these increases has resulted in additional depletion and depreciation expense of approximately $16.72 million; $6.16 million relating to 2007, $5.48 million relating to 2006 and $5.08 million relating to 2005.*

At December 31, 2007, petroleum, natural gas properties and equipment include $22.78 million (2006 – $20.99 million) relating to undeveloped properties that have been excluded from the depletion calculation.

An impairment test calculation was performed on the Trust's petroleum, natural gas properties and equipment at December 31, 2007 in which the estimated undiscounted future net cash flows associated with the proved reserves exceeded the carrying amount of the Trust's petroleum, natural gas properties and equipment; consequently an impairment provision was not recorded. This impairment calculation was performed separately on both the Canadian and US cost centres.

The following table outlines benchmark prices used in the impairment test at December 31, 2007:

Year	WTI Crude Oil ($US/bbl)	Exchange Rate ($US/$Cdn)	WTI Crude Oil ($Cdn/bbl)	AECO Gas ($Cdn/gj)
2008	92.45	1.00	92.45	6.59
2009	87.80	1.00	87.80	7.35
2010	86.32	1.00	86.32	7.63
2011	86.89	1.00	86.89	7.73
2012	86.04	1.00	86.04	7.75
Thereafter (inflation %)	2.0%	1.00	2.0%	2.0%

Actual prices used in the impairment test were adjusted for commodity price differentials specific to Zargon.

5. LONG TERM DEBT

On June 30, 2006, Zargon amended and renewed its 2005 syndicated committed credit facilities, resulting in an increase in the available facilities and borrowing base to $100 million from the previous amount of $80 million. These facilities consisted of an $80 million tranche available to the Canadian borrower and a US $15 million tranche available to the US borrower. On July 30, 2007, Zargon amended and renewed these facilities, the result of which is an increase in the available facilities and borrowing base to $120 million. These facilities consist of a $100 million tranche available to the Canadian borrower and a US $18 million tranche available to the US borrower. A $150 million demand debenture on the assets of the subsidiaries of the Trust has been provided as security for these facilities. The facilities are fully revolving for a 364-day period with the provision for an annual extension at the option of the lenders and upon notice from Zargon's management. The next renewal date is July 29, 2008. Should the facilities not be renewed, they convert to one-year non-revolving term facilities at the end of the revolving 364-day period. Repayment would not be required until the end of the non-revolving term, and as such, these facilities have been classified as long term debt.

Interest rates fluctuate under the syndicated facilities with Canadian prime, US prime, and US base rates plus an applicable margin between zero basis points and 25 basis points, as well as with Canadian banker's acceptance and LIBOR rates plus an applicable margin between 90 basis points and 150 basis points. At December 31, 2007, $56.87 million (2006 – $30.04 million) had been drawn on the syndicated committed credit facilities bearing interest at Canadian prime (December 31, 2007 – 6.0 percent; December 31, 2006 – 6.0 percent) with any unused amounts subject to standby fees. In the normal course of operations Zargon enters into various letters of credit. At December 31, 2007, the approximate value of outstanding letters of credit totalled $0.44 million (2006 – $0.47 million). Refer to note 19 for a subsequent amendment to Zargon's syndicated committed credit facilities.

6. ASSET RETIREMENT OBLIGATIONS

The total future asset retirement obligation was estimated by management based on Zargon's net working interest in all wells and facilities, estimated costs to reclaim and abandon wells and facilities and the estimated timing of the costs to be incurred in future periods. Zargon has estimated the net present value of its total asset retirement obligations to be $21.18 million as at December 31, 2007 (2006 – $17.31 million), based on a total future liability of $101.88 million (2006 – $65.08 million). These payments are expected to be made over the next 40 years with the majority of the costs being incurred after 2016. Commencing July 1, 2005, incremental asset retirement obligations

are calculated using a revised credit adjusted risk-free rate of 7.5 percent. Asset retirement obligations prior to this period were calculated using a credit adjusted risk-free rate of 8.5 percent. An inflation rate of two percent used in the calculation of the present value of the asset retirement obligation remains unchanged. The following table reconciles Zargon's asset retirement obligations:

	Year Ended December 31,	
($ thousands)	**2007**	2006
Balance, beginning of year	**17,307**	15,859
Adjustment to asset retirement obligations	**2,911**	–
Net liabilities incurred	**851**	826
Liabilities settled	**(1,140)**	(627)
Accretion expense	**1,406**	1,244
Foreign exchange	**(151)**	5
Balance, end of year	**21,184**	17,307

7. UNITHOLDERS' EQUITY

Pursuant to the Plan of Arrangement on July 15, 2004, 14.87 million units of the Trust and 3.66 million exchangeable shares (see note 8) of the Company were issued in exchange for all of the outstanding shares of the Company on a one-for-one basis.

The Trust is authorized to issue an unlimited number of voting trust units.

Trust Units

	December 31, 2007		December 31, 2006	
(thousands)	**Number of Units**	**Amount ($)**	Number of Units	Amount ($)
Balance, beginning of year	**16,789**	**82,868**	16,355	71,644
Unit rights exercised for cash	**120**	**2,127**	208	4,018
Unit-based compensation recognized on exercise of unit rights	**–**	**466**	–	728
Issued on conversion of exchangeable shares	**167**	**4,227**	226	6,478
Balance, end of year	**17,076**	**89,688**	16,789	82,868

Trust Unit Rights Incentive Plan

The Trust has a unit rights incentive plan (the "Plan") that allows the Trust to issue rights to acquire trust units to directors, officers, employees and other service providers. The Trust is authorized to issue up to 2.36 million unit rights; however, the number of trust units reserved for issuance upon exercise of the rights shall not at any time exceed 10 percent of the aggregate number of the total outstanding units, including units issuable upon exchange of exchangeable shares of Zargon and other fully paid securities of Zargon entities exchangeable into units, which are the economic equivalent of units including full voting rights. At the time of grant, unit right exercise prices approximate the market price for the trust units. At the time of exercise, the rights holder has the option of exercising at the original grant price or the exercise price as calculated under the Plan (the "modified price"). The modified price is calculated by deducting from the grant price the amount by which monthly distributions, on a per unit basis, made by the Trust after the grant date exceed a monthly return of 0.833 percent of the Trust's recorded net book value of oil and natural gas properties. Rights granted under the Plan generally vest over a three-year period and expire approximately five years from the grant date. Zargon uses a fair value methodology to value the unit rights grants.

The following table summarizes information about the Trust's unit rights:

	December 31, 2007		December 31, 2006	
	Number of Unit Rights (thousands)	Weighted Average Exercise Price Initial and Modified ($/unit right)	Number of Unit Rights (thousands)	Weighted Average Exercise Price Initial and Modified ($/unit right)
Outstanding beginning of year	1,208	26.32 / 24.73	915	22.80 / 21.51
Unit rights granted	522	25.36	518	29.70
Unit rights exercised	(120)	17.73	(208)	19.30
Unit rights cancelled	(122)	28.75	(17)	25.59
Outstanding end of year	1,488	26.41 / 24.60	1,208	26.32 / 24.73
Unit rights exercisable at year end	559	25.51 / 22.66	212	24.11 / 21.78

The following tables summarize information about unit rights outstanding and exercisable at December 31, 2007:

At the initial grant price:

	Unit Rights Outstanding			Unit Rights Exercisable	
Range of Exercise Prices ($/unit right)	Number Outstanding (thousands)	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price ($/unit right)	Number Exercisable (thousands)	Weighted Average Exercise Price ($/unit right)
17.70 – 22.00	261	1.6 years	19.77	218	19.33
22.75 – 25.06	378	3.8 years	23.98	43	24.91
26.65 – 29.93	485	3.3 years	27.89	126	28.16
31.09 – 33.05	364	2.7 years	31.72	172	31.55
	1,488		26.41	559	25.51

At the modified price:

	Unit Rights Outstanding			Unit Rights Exercisable	
Range of Exercise Prices ($/unit right)	Number Outstanding (thousands)	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price ($/unit right)	Number Exercisable (thousands)	Weighted Average Exercise Price ($/unit right)
13.72 – 18.71	261	1.6 years	16.12	218	15.61
21.88 – 23.79	378	3.8 years	23.30	43	23.67
24.33 – 27.84	485	3.3 years	26.34	126	25.38
28.37 – 31.65	364	2.7 years	29.73	172	29.36
	1,488		24.60	559	22.66

Unit-Based Compensation

The weighted average assumptions used for unit rights granted in 2007 include a volatility factor of expected market price of 26.3 percent, a risk-free interest rate of 4.2 percent, a dividend yield of 8.6 percent and an expected life of the unit rights of four years. These unit rights, together with the continued vesting of unit rights granted in prior years, resulted in unit-based compensation expense in 2007 of $1.71 million (2006 – $1.86 million).

Compensation expense associated with unit rights granted under the Plan is recognized in earnings over the vesting period of the Plan with a corresponding increase in contributed surplus. The exercise of trust unit rights is recorded as an increase in trust units with a corresponding reduction in contributed surplus. Forfeiture of rights are recorded as a reduction in expenses in the period in which they occur.

The following table summarizes information about the Trust's contributed surplus account:

Contributed Surplus

($ thousands)	
Balance, December 31, 2005	1,347
Unit-based compensation expense	1,856
Unit-based compensation recognized on exercise of unit rights	(728)
Balance, December 31, 2006	**2,475**
Unit-based compensation expense	**1,705**
Unit-based compensation recognized on exercise of unit rights	**(466)**
Balance, December 31, 2007	**3,714**

Trust Unit Redemption

Under the terms of the Trust Indenture, unitholders may require the Trust to redeem all or any part of the trust units at a price and under certain terms and conditions as specified in the Trust Indenture. The redemption price per trust unit will be equal to the lesser of: (i) 90 percent of the "market price" of the trust units on the principal market on which the trust units are quoted for trading during the 10 trading day period commencing immediately after the date on which the trust units are tendered to Zargon for redemption; and (ii) the closing market price on the principal market on which the trust units are quoted for trading on the date that the trust units are so tendered for redemption. Trust units tendered for redemption in any calendar month shall be paid on the last day of the third following month by, at the Trust's option: (i) a cash payment; or (ii) a distribution of notes and/or redemption notes. It is anticipated that this redemption right will not be the primary mechanism for holders of trust units to dispose of their trust units. Notes or redemption notes which may be distributed in specie to unitholders in connection with a redemption will not be listed on any stock exchange and no market is expected to develop for such notes or redemption notes. Notes or redemption notes may not be qualified investments for trusts governed by registered retirement savings plans, registered retirement income funds, deferred profit sharing plans and registered education savings plans. To date, no trust units have been tendered for redemption.

8. NON-CONTROLLING INTEREST—EXCHANGEABLE SHARES

Zargon Oil & Gas Ltd. is authorized to issue an unlimited number of exchangeable shares. The exchangeable shares are convertible into trust units at the option of the shareholder, based on the exchange ratio, which is adjusted monthly to reflect the distribution paid on the trust units. Cash distributions are not paid on the exchangeable shares. During the year, a total of 0.14 million (2006 – 0.20 million) exchangeable shares were converted into 0.17 million (2006 – 0.23 million) trust units based on the exchange ratio at the time of conversion. At December 31, 2007, the exchange ratio was 1.29611 (December 31, 2006 – 1.19403) trust units per exchangeable share. As set out in the Arrangement, the exchangeable shares are entitled to vote equally to the number of trust units for which each exchangeable share is convertible into a trust unit on the record date. The Board of Directors of Zargon Oil & Gas Ltd. hold the option to redeem all outstanding exchangeable shares for trust units on or before July 15, 2014. At such time, should the Board of Directors not extend the term of the exchangeable shares, there would be no remaining non-controlling interest.

Pursuant to EIC-151 "Exchangeable Securities Issued by a Subsidiary of an Income Trust", if certain conditions are met, the exchangeable shares issued by a subsidiary must be reflected as non-controlling interest on the consolidated balance sheets and in turn, net earnings must be reduced by the amount of net earnings attributed to the non-controlling interest.

The non-controlling interest on the consolidated balance sheets consists of the book value of exchangeable shares at the time of the Plan of Arrangement, plus net earnings attributable to the exchangeable shareholders, less exchangeable shares (and related cumulative earnings) redeemed. The net earnings attributable to the non-controlling interest on the consolidated statements of earnings and comprehensive income represents the cumulative share of net earnings attributable to the non-controlling interest based on the trust units issuable for exchangeable shares in proportion to total trust units issued and issuable each year end.

Non-Controlling Interest – Exchangeable Shares

(thousands, except exchange ratio)	December 31, 2007 Number of Shares	December 31, 2007 Amount ($)	December 31, 2006 Number of Shares	December 31, 2006 Amount ($)
Balance, beginning of year	**2,207**	**18,319**	2,402	12,673
Exchanged for trust units at book value and including net earnings attributed during the year	**(136)**	**(1,394)**	(195)	(1,492)
Earnings attributable to non-controlling interest	**–**	**3,805**	–	7,138
Balance, end of year	**2,071**	**20,730**	2,207	18,319
Exchange ratio, end of year	**1.29611**		1.19403	
Trust units issuable upon conversion of exchangeable shares, end of year	**2,684**		2,635	

The proforma total units outstanding at December 31, 2007, including trust units outstanding, and trust units issuable upon conversion of exchangeable shares and after giving rise to the exchange ratio at the end of the year, is 19.76 million units (2006 – 19.42 million units).

The effect of EIC-151 on Zargon's unitholders' capital and exchangeable shares is as follows:

($ thousands)	Zargon Energy Trust Units	Zargon Oil & Gas Ltd. Exchangeable Shares	Total
Balance at December 31, 2005	71,644	12,673	84,317
Issued on redemption of exchangeable shares at book value	477	(477)	–
Effect of EIC-151	6,001	6,123	12,124
Unit-based compensation recognized on exercise of unit rights	728	–	728
Unit rights exercised for cash	4,018	–	4,018
Balance at December 31, 2006	**82,868**	**18,319**	**101,187**
Issued on redemption of exchangeable shares at book value	**330**	**(330)**	**–**
Effect of EIC-151	**3,897**	**2,741**	**6,638**
Unit-based compensation recognized on exercise of unit rights	**466**	**–**	**466**
Unit rights exercised for cash	**2,127**	**–**	**2,127**
Balance at December 31, 2007	**89,688**	**20,730**	**110,418**

EIC-151 "Exchangeable Securities Issued by Subsidiaries of Income Trusts" states that exchangeable securities issued by a subsidiary of an Income Trust should be reflected as either a non-controlling interest or debt on the consolidated balance sheets unless they meet certain criteria. The exchangeable shares issued by Zargon Oil & Gas Ltd., a corporate subsidiary of the Trust, are publicly traded and have an expiry term, which could be extended at the option of the Board of Directors. Therefore, these securities are considered, by EIC-151, to be transferable to third parties and to have an indefinite life. EIC-151 states that if these criteria are met, the exchangeable shares should be reflected as a non-controlling interest.

As a result of EIC-151, the Trust has increased its unitholders' equity and non-controlling interest for 2007 by $6.64 million (2006 – $12.12 million) on the Trust's consolidated balance sheets. Consolidated net earnings for 2007 have been reduced for net earnings attributable to the non-controlling interest by $3.81 million (2006 – $7.14 million). In accordance with EIC-151 and given the circumstances in Zargon's case, each redemption is accounted for as a step-purchase, which for 2007 additionally resulted in an increase in property and equipment of $8.82 million (2006 – $6.73 million), and an increase in future income tax liability of $5.99 million (2006 – $1.75 million). Funds flow from operations were not impacted by this change.

The cumulative impact to date of the application of EIC-151 has been to increase gross property and equipment by $51.76 million (for depletion impact see note 4), unitholders' equity and non-controlling interest by $53.35 million, future income tax liability by $17.22 million and an allocation of net earnings to exchangeable shareholders of $18.81 million.

9. INCOME TAXES

The Trust is a taxable entity under the Income Tax Act (Canada) and, until 2011, is taxable only on income that is not distributed or distributable to the unitholders. As the Trust allocates all of its Canadian taxable income to the unitholders in accordance with the Trust Indenture, and meets the requirements of the Income Tax Act (Canada) applicable to the Trust, no current tax provision for Canadian income tax expense has been incurred by the Trust. Provincial capital taxes and US income taxes are provided for under current income tax expense.

In the Trust's structure, payments are made between the Company and the Trust that result in the transferring of taxable income from the Company to individual unitholders. These payments may reduce future income tax liabilities previously recorded by the Company that would be recognized as a recovery of income tax in the period incurred.

On October 31, 2006, the Federal Government announced tax proposals pertaining to taxation of distributions paid by trusts and the personal tax treatment of trust distributions. Currently, the Trust does not pay tax on distributions as tax is paid by the unitholders. On June 12, 2007, the Federal Government enacted these tax proposals, which will result in taxation of distributions at the Trust level at a rate of 31.5 percent effective January 1, 2011. Subsequent 2007 fourth quarter legislation has lowered this tax rate to 29.5 percent in 2011 and 28.0 percent beyond 2011 to assimilate recent corporate tax rate changes. Prior to June 2007, the Trust estimated the future income tax on certain temporary differences between amounts recorded on its consolidated balance sheets for book and tax purposes to have a nil effective tax rate. Under the legislation, the Trust now estimates the effective tax rate on the post 2010 reversal of these temporary differences to be approximately 28.0 percent. Until 2011, Zargon's future tax obligations are reduced as distributions are made from the Trust and, consequently, it is anticipated that Zargon's effective tax rate will continue to be low until that time.

Based on its assets and liabilities as at June 30, 2007, the quarter in which the tax proposals were substantively enacted, the Trust had estimated the amount of its temporary differences, which were previously not subject to tax and had estimated the periods in which these differences will reverse. The Trust estimated that $7.05 million of net tax deductible temporary differences will reverse after January 1, 2011, which resulted in a reduction of the future tax liability of $2.22 million in the 2007 second quarter. The taxable temporary differences relate principally to the remaining tax pools attributed to the oil and gas properties being greater than their net book value. The year-over-year increase in the future tax recovery reflects these legislated adjustments.

While the Trust believes it will be subject to additional tax under the new legislation, the estimated effective rate on temporary difference reversals after 2011 may change in future periods. As the legislation is new, future technical interpretations could occur and could materially affect management's estimate of the future tax liability.

The amount and timing of reversals of temporary differences will also depend on the Trust's future operating results, acquisitions and dispositions of assets and liabilities, and distributions. A significant change in any of the preceding assumptions could materially affect management's estimate of the future tax liability.

Income taxes differ from the amounts which would be obtained by applying the statutory income tax rates to earnings before income taxes as follows:

($ thousands)	2007	2006
Statutory income tax rates	33.03%	36.30%
Expected income taxes	4,964	18,300
Add (deduct) income tax effect of:		
Non-deductible Crown charges	–	2,145
Resource allowance	–	(2,397)
Rate adjustments	(5,775)	(8,865)
Impact of changes in tax rates relating to income trusts after 2010	(2,220)	–
Cash distributions	(12,120)	(13,032)
Capital taxes and US income taxes	2,143	1,598
Other	(319)	1,025
	(13,327)	(1,226)

The 2007 and 2006 years include recoveries relating to reductions in future federal and provincial income tax rates substantively enacted during the respective years.

Future income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes.

The components of Zargon's net future income tax liability are as follows:

($ thousands)	2007	2006
Net book value of property and equipment in excess of tax pools	**43,469**	46,336
Deferred partnership earnings	**4,762**	6,024
Asset retirement obligations	**(7,051)**	(6,333)
Unrealized risk management asset/(liability)	**(3,633)**	2,104
Share issue costs	**(57)**	(8)
Other	**(232)**	(232)
	37,258	47,891

As at December 31, 2007, Zargon's estimated tax pools are as follows:

($ thousands)	December 31, 2007
Canadian oil and gas property expenses in the Trust	**37,772**
Canadian oil and gas property expenses in other entities	**7,821**
Canadian development expenses	**27,224**
Canadian exploration expenses	**45,125**
Capital cost allowance	**40,441**
US tax pools	**4,440**
Partnership deferral	**(15,815)**
Other	**1,248**
	148,256

10. WEIGHTED AVERAGE NUMBER OF TOTAL UNITS

(thousands of units)	2007	2006
Basic	**16,975**	16,600
Diluted	**19,551**	19,244

Dilution amounts of 2.58 million units (2006 – 2.64 million) were added to the weighted average number of units outstanding during the year in the calculation of diluted per unit amounts. These unit additions represent the dilutive effect of unit rights according to the treasury stock method and also include exchangeable shares using the "if-converted" method. Due to the fact that at the time of exercise, the rights holder has the option of exercising at the original grant price or a modified price as calculated under the Plan, the prices used in the treasury stock calculation are the lower prices calculated under the Plan. An adjustment to the numerator amount was required in the diluted calculation to provide for the earnings of $3.81 million (2006 – $7.14 million) attributable to the non-controlling interest pertaining to the exchangeable shareholders.

11. FINANCIAL INSTRUMENTS

Fair Value of Financial Assets and Liabilities

Financial instruments of the Trust consist of accounts receivable, deposits, accounts payable, cash distributions payable, unrealized risk management assets and liabilities and long term debt. As at December 31, 2007 and 2006, there are no significant differences between the carrying values of these instruments and their estimated market values.

Credit Risk Management

Accounts receivable include amounts receivable for petroleum and natural gas sales that are generally made to large credit worthy purchasers, and amounts receivable from joint venture partners that are recoverable from production. Accordingly, management views credit risks on these amounts as low. Of Zargon's significant individual accounts receivable at December 31, 2007, approximately 22 percent was owing from one company (2006 – 26 percent).

The Trust is exposed to losses in the event of non-performance by counterparties to financial risk management contracts. The Trust minimizes credit risk associated with possible non-performance of these counterparties by entering into contracts with only investment grade counterparties, limiting exposure to any one counterparty and monitoring procedures. Management believes these risks are minimal.

Interest Rate Risk Management

Borrowings under bank credit facilities are market rate based (variable interest rates); thus, carrying values approximate fair values.

Foreign Currency Risk Management

The Trust is exposed to fluctuations in the exchange rate between the Canadian dollar and the US dollar. Crude oil, and to a large extent natural gas prices, are based upon reference prices denominated in US dollars, while the majority of the Trust's expenses are denominated in Canadian dollars. When considered appropriate, the Trust enters into agreements to fix the exchange rate of the Canadian dollar to the US dollar in order to manage this risk.

Commodity Price Risk Management

The Trust is a party to certain financial instruments that have fixed the price of a portion of its oil and natural gas production. The Trust enters into these contracts for risk management purposes only, in order to protect a portion of its future cash flows from the volatility of oil and natural gas commodity prices.

Financial Contracts at December 31, 2007:

	Rate	Weighted Average Price	Range of Terms	Fair Market Value Gain/(Loss) ($ thousands)
Oil swaps	300 bbl/d	$66.70 US/bbl	Jan. 1/08–Mar. 31/08	(777)
	300 bbl/d	$61.72 US/bbl	Jan. 1/08–Jun. 30/08	(1,779)
	600 bbl/d	$71.54 US/bbl	Jan. 1/08–Dec. 31/08	(4,687)
	500 bbl/d	$87.58 US/bbl	Jan. 1/08–Jun. 30/09	(1,086)
	300 bbl/d	$68.29 US/bbl	Apr. 1/08–Jun. 30/08	(690)
	600 bbl/d	$68.94 US/bbl	Jul. 1/08–Dec. 31/08	(2,468)
	500 bbl/d	$72.74 US/bbl	Jan. 1/09–Mar. 31/09	(747)
	500 bbl/d	$85.30 US/bbl	Jul. 1/09–Dec. 31/09	(196)
Natural gas swaps	6,000 gj/d	$8.41/gj	Jan. 1/08–Mar. 31/08	1,147
	1,000 gj/d	$7.84/gj	Apr. 1/08–Oct. 31/08	285
Net Fair Market Value, Financial Contracts				**(10,998)**

Oil swaps are settled against the NYMEX pricing index, whereas natural gas swaps are settled against the AECO pricing index.

For financial risk management contracts, the Trust considers these contracts to be effective on an economic basis but has decided not to designate these contracts as hedges for accounting purposes and accordingly, any unrealized gains or losses are recorded based on the fair value (mark-to-market) of the contracts at the year end. The unrealized loss for 2007 was $16.80 million and the unrealized gain for 2006 was $9.55 million.

Contracts settled by way of physical delivery are recognized as part of the normal revenue stream. These instruments have no book values recorded in the consolidated financial statements.

Physical Contract at December 31, 2007:

	Rate	Weighted Average Price	Range of Terms	Fair Market Value Gain ($ thousands)
Natural gas fixed price	1,000 gj/d	$7.95/gj	Apr. 1/08–Oct. 31/08	308

12. COMMITMENTS

The Trust is committed to future minimum payments for natural gas transportation contracts in addition to operating leases for office space, office equipment, vehicles and field equipment. Payments required under these commitments for each of the next five years are: 2008 – $2.02 million; 2009 – $1.48 million; 2010 – $1.23 million; 2011 – $1.23 million; 2012 – $0.71 million; thereafter – nil.

13. CONTINGENCIES AND GUARANTEES

In the normal course of operations, Zargon executes agreements that provide for indemnification and guarantees to counterparties in transactions such as the sale of assets and operating leases.

These indemnifications and guarantees may require compensation to counterparties for costs and losses incurred as a result of various events, including breaches of representations and warranties, loss of or damages to property, environmental liabilities or as a result of litigation that may be suffered by counterparties.

Certain indemnifications can extend for an unlimited period and generally do not provide for any limit on the maximum potential amount. The nature of substantially all of the indemnifications prevents the Trust from making a reasonable estimate of the maximum potential amount that might be required to pay counterparties as the agreements do not specify a maximum amount, and the amounts depend on the outcome of future contingent events, the nature and likelihood of which cannot be determined at this time.

The Trust indemnifies its directors and officers against any and all claims or losses reasonably incurred in the performance of their services to the Trust to the extent permitted by law. The Trust has acquired and maintains liability insurance for its directors and officers. The Trust is party to various legal claims associated with the ordinary conduct of business. The Trust does not anticipate that these claims will have a material impact on its financial position.

14. CHANGES IN NON-CASH WORKING CAPITAL

	Year Ended December 31	
($ thousands)	**2007**	2006
Changes in non-cash working capital items:		
Accounts receivable	**(3,306)**	3,473
Prepaid expenses and deposits	**136**	(571)
Accounts payable and accrued liabilities	**(1,238)**	(2,160)
Cash distributions payable	**52**	(8,100)
Foreign exchange and other	**(1,076)**	17
	(5,432)	(7,341)
Changes relating to operating activities	**(3,535)**	842
Changes relating to financing activities	**52**	(8,099)
Changes relating to investing activities	**(1,949)**	(84)
	(5,432)	(7,341)

15. SUPPLEMENTAL CASH FLOW INFORMATION

($ thousands)	**2007**	2006
Cash interest paid	**3,259**	1,593
Cash taxes paid	**2,972**	2,216

16. SEGMENTED INFORMATION

Zargon's entire operating activities are related to exploration, development and production of oil and natural gas in the geographic regions of Canada and the US.

		2007	
($ thousands)	**Canada**	**United States**	**Combined**
Petroleum and natural gas revenue	**133,473**	**22,039**	**155,512**
Earnings before income taxes	**5,703**	**9,327**	**15,030**
Property and equipment, net	**278,444**	**35,505**	**313,949**
Total assets	**301,643**	**38,551**	**340,194**
Net capital expenditures	**63,591**	**3,078**	**66,669**

		2006	
($ thousands)	Canada	United States	Combined
Petroleum and natural gas revenue	129,967	24,072	154,039
Earnings before income taxes	39,797	10,614	50,411
Property and equipment, net	248,440	34,668	283,108
Total assets	273,748	36,820	310,568
Net capital expenditures	58,040	5,326	63,366

17. CASH DISTRIBUTIONS

During the year, the Trust declared distributions to the unitholders in the aggregate amount of $36.70 million (2006 – $35.90 million) in accordance with the following schedule:

2007 Distributions	Record Date	Distribution Date	Per Trust Unit
January	January 31, 2007	February 15, 2007	$0.18
February	February 28, 2007	March 15, 2007	$0.18
March	March 31, 2007	April 16, 2007	$0.18
April	April 30, 2007	May 15, 2007	$0.18
May	May 31, 2007	June 15, 2007	$0.18
June	June 30, 2007	July 16, 2007	$0.18
July	July 31, 2007	August 15, 2007	$0.18
August	August 31, 2007	September 17, 2007	$0.18
September	September 30, 2007	October 15, 2007	$0.18
October	October 31, 2007	November 15, 2007	$0.18
November	November 30, 2007	December 17, 2007	$0.18
December	December 31, 2007	January 15, 2008	$0.18

2006 Distributions	Record Date	Distribution Date	Per Trust Unit
January	January 31, 2006	February 15, 2006	$0.18
February	February 28, 2006	March 15, 2006	$0.18
March	March 31, 2006	April 17, 2006	$0.18
April	April 30, 2006	May 15, 2006	$0.18
May	May 31, 2006	June 15, 2006	$0.18
June	June 30, 2006	July 17, 2006	$0.18
July	July 31, 2006	August 15, 2006	$0.18
August	August 31, 2006	September 15, 2006	$0.18
September	September 30, 2006	October 16, 2006	$0.18
October	October 31, 2006	November 15, 2006	$0.18
November	November 30, 2006	December 15, 2006	$0.18
December	December 31, 2006	January 15, 2007	$0.18

18. RELATED PARTY TRANSACTIONS

Zargon paid $0.05 million (2006 – $0.05 million) for vehicle leases to a company owned by a Board member; $0.07 million (2006 – $0.09 million) for legal services to a law firm of which a Board member is a partner; nil (2006 – $0.02 million) for field services to a company of which a senior Zargon officer is a Board member and nominal shareholder; and nil (2006 – $0.06 million) in consulting fees to a company owned by a Board member. These payments were in the normal course of operations, were made on commercial terms, and therefore were recorded at their exchange amounts.

19. SUBSEQUENT EVENTS

On January 23, 2008, Zargon completed the acquisition of Rival Energy Ltd. ("Rival") for consideration comprising 0.57 million Zargon trust units and $16.40 million in cash for all the issued and outstanding Rival common shares. Pursuant to the Rival Plan of Arrangement, Rival shareholders had the option of electing to receive 0.0562 Zargon trust units or $1.35 for each Rival common share, up to an aggregate maximum of $16.40 million in cash. The first post-Arrangement distribution by Zargon was paid on February 15, 2008 to Zargon unitholders (including former Rival shareholders who had elected to receive and continue to hold Zargon trust units) of record on January 31, 2008.

On January 31, 2008, Zargon amended its syndicated committed credit facilities, the result of which is an increase in the available facilities and borrowing base to $150 million. These facilities consist of a $130 million tranche available to the Canadian borrower and a US $18 million tranche available to the US borrower. A $300 million demand debenture on the assets of the subsidiaries of the Trust has been provided as security for these facilities.

On March 12, 2008, Zargon entered into an Acquisition Agreement pursuant to which Zargon has agreed to make an offer to acquire all the issued and outstanding common shares of Newpact Energy Corp. ("Newpact") and assume approximately $3.65 million of net debt subject to a number of conditions. Pursuant to the Newpact Acquisition Agreement, Newpact shareholders will receive approximately 0.43 million Zargon trust units or approximately 0.0534 trust units for each Newpact common share.

Six-Year Summary

	2007	2006	2005	2004	2003	2002
FINANCIAL ($ thousands, except per unit amounts)						
Petroleum and natural gas revenue	**155,512**	154,039	162,722	123,968	101,657	65,538
Less expenses – cash items						
Royalties	**32,746**	33,431	37,319	28,047	22,508	13,508
Production	**32,620**	26,416	24,035	21,692	17,201	15,649
General and administrative	**8,209**	6,973	6,053	4,358	3,542	3,455
Realized risk management (gain)/loss	**(4,255)**	569	7,754	4,568	2,882	(669)
Interest and financing charges	**3,071**	1,532	786	440	771	1,100
Current and capital taxes	**2,143**	1,598	1,801	1,114	406	378
Asset retirement expenditures	**1,140**	627	604	414	287	423
Funds flow from operations	**79,838**	82,893	84,370	63,335	54,060	31,694
Less expenses – non-cash items						
Depletion, depreciation and foreign exchange	**48,184**	41,160	37,283	26,850	19,363	14,148
Unrealized risk management (gain)/loss	**16,796**	(9,553)	3,756	–	–	–
Future income tax (recovery)	**(15,470)**	(2,824)	474	9,639	9,187	6,558
Accretion of asset retirement obligations	**1,406**	1,244	1,196	1,076	1,172	715
Unit-based compensation	**1,705**	1,856	902	3,682	264	–
Earnings before non-controlling interest	**28,357**	51,637	41,363	22,502	24,361	10,696
Less non-controlling interest – exchangeable shares	**3,805**	7,138	5,994	1,870	–	–
Net earnings	**24,552**	44,499	35,369	20,632	24,361	10,696
Per unit, diluted						
Funds flow from operations	**4.08**	4.31	4.48	3.38	2.94	1.78
Net earnings	**1.45**	2.68	2.19	1.20	1.33	0.60
Net capital expenditures	**66,669**	63,366	54,684	56,273	39,909	35,548
Cash distributions	**36,695**	35,902	37,444	10,702	–	–
Cash distributions ($/trust unit)	**2.16**	2.16	2.32	0.70	–	–
Balance sheet at year end						
Property and equipment, net	**313,949**	283,108	253,315	209,736	167,888	147,404
Bank debt	**56,868**	30,037	10,339	14,230	6,978	25,279
Unitholders' equity	**161,478**	165,562	144,613	120,622	112,469	86,699
Unitholders' equity ($/total units)	**8.17**	8.53	7.62	6.48	6.25	4.92
Year end total units outstanding (thousands)	**19,761**	19,424	18,988	18,610	17,992	17,637

	2007	2006	2005	2004	2003	2002
OPERATING						
Total production (boe/d)	**8,560**	8,422	8,342	8,222	7,446	6,349
Oil and liquids (bbl/d)	**3,675**	3,805	3,697	3,416	3,287	2,968
Natural gas (mmcf/d)	**29.31**	27.70	27.87	28.84	24.95	20.29
Equivalent per million trust units (boe/d)	**436**	437	445	447	418	368
Total proved reserves (mboe)	**18,741**	19,050	19,243	19,049	18,664	21,592
Proved oil and liquids (mbbl)	**11,434**	11,523	11,490	10,954	10,505	11,114
Proved natural gas (bcf)	**43.86**	45.15	46.52	48.57	48.96	62.87
Total proved and probable reserves (mboe)	**26,908**	27,464	26,771	25,955	24,745	23,983
Proved and probable oil and liquids (mbbl)	**15,683**	15,937	15,354	14,361	13,566	12,445
Proved and probable natural gas (bcf)	**67.36**	69.15	68.50	69.56	67.07	69.23
Equivalent per total unit (boe)	**1.36**	1.41	1.41	1.39	1.38	1.36
Average selling price before the impact of financial risk management contracts						
WTI crude oil price ($US/bbl)	**72.31**	66.22	56.56	41.40	31.04	26.08
Edmonton par crude oil price ($Cdn/bbl)	**76.35**	72.77	68.72	52.54	43.14	39.94
Zargon realized crude oil price ($Cdn/bbl)	**64.71**	61.25	57.15	45.37	36.66	34.45
NYMEX average daily spot natural gas price ($US/mmbtu)	**6.98**	6.75	8.89	5.90	5.49	3.35
AECO average daily spot natural gas price ($Cdn/mmbtu)	**6.45**	6.54	8.77	6.55	6.70	4.18
Zargon realized natural gas price ($Cdn/mcf)	**6.40**	6.82	8.41	6.37	6.33	3.81
Other data						
Wells drilled, net	**46.9**	76.2	53.5	49.5	38.6	31.6
Undeveloped land (thousand net acres)	**362**	381	367	376	398	331
Closing trust unit price ($/unit)	**23.06**	24.79	31.75	23.85	13.50	9.00

Notes:

Throughout this report, funds flow from operations, funds flow from operations per diluted unit and funds flow netbacks are now calculated inclusive of asset retirement expenditures. All prior period calculations have been restated to reflect this change.

Throughout this report, the calculation of barrels of oil equivalent ("boe") is based on the conversion ratio that six thousand cubic feet of natural gas is equivalent to one barrel of oil. For a further discussion about this term, refer to the Management's Discussion and Analysis section in this report.

Funds flow from operations is a non-GAAP term that represents net earnings and asset retirement expenditures except for non-cash items. For a further discussion about this term, refer to the Management's Discussion and Analysis section in this report.

For net capital expenditures, amounts include capital expenditures acquired for cash and equity issuances.

Cash distributions to unitholders commenced subsequent to the reorganization of the Company into a Trust effective July 15, 2004.

Total units outstanding include trust units plus exchangeable shares outstanding at year end. The exchangeable shares are converted at the exchange ratio at the end of the year.

Average daily production per million trust units is calculated using the weighted average number of units outstanding during the year, plus the weighted average number of exchangeable shares outstanding for the year converted at the average exchange ratio for the year.

In this table the established reserves (proved plus 50 percent probable) for the prior year (2002) are used as a comparison to 2003, 2004, 2005, 2006 and 2007 proved and probable reserves. This adjustment is necessary due to the change in reserve risk assessments required to comply with NI 51-101 reserve guidelines.

Certain comparative period numbers reflect retroactive restatement due to a change in accounting policy.

Corporate Information

BOARD OF DIRECTORS

Craig H. Hansen
Calgary, Alberta

K. James Harrison
Chairman of the Board
Oakville, Ontario

Kyle D. Kitagawa[1][2]
Calgary, Alberta

James J. Lawson[3][4]
Oakville, Ontario

John O. McCutcheon[3]
Vancouver, British Columbia

Margaret A. McKenzie[1][3]
Calgary, Alberta

Jim Peplinski[2][4]
Calgary, Alberta

J. Graham Weir[1][2]
Calgary, Alberta

Grant A. Zawalsky[3][4]
Calgary, Alberta

OFFICERS

Craig H. Hansen
President and Chief Executive Officer

Brent C. Heagy
Executive Vice President and Chief Financial Officer

Daniel A. Roulston
Executive Vice President, Operations

Henry J. Baird
Vice President, Exploitation

Jason B. Dranchuk
Controller and Treasurer

Tracy L. Howard
Corporate Secretary

Brian G. Kergan
Vice President, Corporate Development and Reserves

Mark I. Lake
Vice President, Exploration

Lorne D. Schwetz
Vice President, Land

(1) Audit Committee
(2) Reserves Committee
(3) Governance and Nominating Committee
(4) Compensation Committee

STOCK EXCHANGE LISTING

The Toronto Stock Exchange

Zargon Energy Trust
Trust Units
Trading Symbol: ZAR.UN

Zargon Oil & Gas Ltd.
Exchangeable Shares
Trading Symbol: ZOG.B

TRANSFER AGENT

Valiant Trust Company
310, 606 - 4th Street S.W.
Calgary, Alberta T2P 1T1

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Calgary, Alberta T2P 2Z1

Canadian Imperial Bank of Commerce
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WEBSITE

www.zargon.ca

ANNUAL MEETING

The annual meeting of the Unitholders of Zargon Energy Trust will be held on Wednesday, April 23, 2008 at 3:00 pm (Calgary time) in the Strand/Tivoli Room of the Metropolitan Conference Centre, 333 - 4th Avenue S.W., Calgary, Alberta.

ABBREVIATIONS

bbl	Barrel
bbl/d	Barrels per day
bcf	Billion cubic feet
boe	Barrels of oil equivalent (6 mcf is equivalent to 1 bbl)
boe/d	Barrels of oil equivalent per day
btu	British thermal units
F&D	Finding and development
FD&A	Finding, development and acquisition
gj	Gigajoule
gj/d	Gigajoules per day
m	Thousand
mm	Million
mcf	Thousand cubic feet
mcf/d	Thousand cubic feet per day
PV	Present value
PVBT	Present value before tax

Forward Looking Statements *– This document contains statements that are forward-looking, such as those relating to results of operations and financial condition, general economic conditions, industry conditions, changes in regulatory and taxation regimes, volatility of commodity prices, escalation of operating and capital costs, currency fluctuations, the availability of services, imprecision of reserve estimates, geological, technical, drilling and processing problems, environmental risks, weather, the lack of availability of qualified personnel or management, stock market volatility, the ability to access sufficient capital from internal and external sources and competition from other industry participants for, among other things, capital, services, acquisitions of reserves, undeveloped lands and skilled personnel. By their nature, forward-looking statements are subject to numerous risks and uncertainties that could significantly affect anticipated results in the future and, accordingly, actual results may differ materially from those predicted. The forward-looking statements contained in this document are as of March 12, 2008 and are subject to change after this date. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Zargon disclaims, except as required by law, any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events, or otherwise.*

Barrels of Oil Equivalent *– Barrels of oil equivalent ("boe") may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.*

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